WILLIAMS COMPANIES INC
Form 10-Q
November 01, 2007

**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C. 20549**
**FORM 10-Q**

**(Mark One)**

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

**For the quarterly period ended September 30, 2007**

**or**

o **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 1-4174**

**THE WILLIAMS COMPANIES, INC.**

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| DELAWARE | 73-0569878 |
| (State of Incorporation) | (IRS Employer Identification Number) |
| ONE WILLIAMS CENTER, TULSA, OKLAHOMA | 74172 |
| (Address of principal executive office) | (Zip Code) |

Registrant s telephone number: (918) 573-2000

NO CHANGE

Former name, former address and former fiscal year, if changed since last report.

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 þ No o

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.

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act.)

Yes o No þ

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

| Class | Outstanding at October 30, 2007 |
|---|---|
| Common Stock, $1 par value | 593,526,517 Shares |

**The Williams Companies, Inc.**
**Index**



Certain matters contained in this report include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

All statements, other than statements of historical facts, included in this report which address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as anticipates, believes, could, may, should, continues, estimates, expects, forecasts, might, planned, potential, projects, expressions. These forward-looking statements include, among others, statements regarding:

Amounts and nature of future capital expenditures;

Expansion and growth of our business and operations;

Business strategy;

Estimates of proved gas and oil reserves;

Reserve potential;

Development drilling potential;

Cash flow from operations;

Seasonality of certain business segments;

Power, natural gas, and natural gas liquids prices and demand.

Table of Contents

Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this document. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

Availability of supplies (including the uncertainties inherent in assessing and estimating future natural gas reserves), market demand, volatility of prices, and increased costs of capital;

Inflation, interest rates, fluctuation in foreign exchange, and general economic conditions;

The strength and financial resources of our competitors;

Development of alternative energy sources;

The impact of operational and development hazards;

Costs of, changes in, or the results of laws, government regulations including proposed climate change legislation, environmental liabilities, litigation, and rate proceedings;

Changes in the current geopolitical situation;

Risks related to strategy and financing, including restrictions stemming from our debt agreements and our lack of investment grade credit ratings;

Risks associated with future weather conditions and acts of terrorism.

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations and do not intend to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part I, Item IA. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006, and Part II, Item 1A. Risk Factors of this Form-10Q.

Table of Contents

**The Williams Companies, Inc.**
**Consolidated Statement of Income**
**(Unaudited)**

| (Dollars in millions, except per-share amounts) | Three months ended September 30, 2007 | Three months ended September 30, 2006* | Nine months ended September 30, 2007 | Nine months ended September 30, 2006* |
|---|---|---|---|---|
| Revenues: | | | | |
| Exploration & Production | $ 499.3 | $ 371.1 | $ 1,521.5 | $ 1,069.4 |
| Gas Pipeline | 392.8 | 334.2 | 1,178.4 | 1,005.5 |
| Midstream Gas & Liquids | 1,360.9 | 1,127.0 | 3,605.5 | 3,168.4 |
| Gas Marketing Services | 1,246.9 | 1,320.6 | 3,928.6 | 3,861.3 |
| Other | 6.5 | 6.4 | 19.8 | 19.8 |
| Intercompany eliminations | (646.3) | (647.5) | (2,202.0) | (2,005.8) |
| Total revenues | 2,860.1 | 2,511.8 | 8,051.8 | 7,118.6 |
| Segment costs and expenses: | | | | |
| Costs and operating expenses | 2,221.3 | 2,039.6 | 6,244.8 | 5,778.9 |
| Selling, general and administrative expenses | 107.8 | 113.0 | 317.3 | 266.6 |
| Other (income) expense net | (2.5) | (7.3) | (38.4) | 37.0 |
| Total segment costs and expenses | 2,326.6 | 2,145.3 | 6,523.7 | 6,082.5 |
| General corporate expenses | 40.2 | 35.0 | 115.8 | 99.3 |
| Securities litigation settlement and related costs | | 3.4 | | 165.3 |
| Operating income (loss): | | | | |
| Exploration & Production | 158.4 | 138.9 | 545.7 | 395.4 |
| Gas Pipeline | 161.9 | 99.3 | 473.3 | 339.0 |
| Midstream Gas & Liquids | 279.6 | 207.6 | 668.9 | 477.1 |
| Gas Marketing Services | (66.8) | (75.7) | (160.1) | (165.0) |
| Other | .4 | (3.6) | .3 | (10.4) |
| General corporate expenses | (40.2) | (35.0) | (115.8) | (99.3) |
| Securities litigation settlement and related costs | | (3.4) | | (165.3) |
| Total operating income | 493.3 | 328.1 | 1,412.3 | 771.5 |
| Interest accrued | (170.8) | (161.0) | (514.9) | (502.2) |
| Interest capitalized | 9.2 | 4.8 | 20.8 | 11.8 |
| Investing income | 77.8 | 51.1 | 195.7 | 137.9 |
| Early debt retirement costs | | | | (31.4) |
| Minority interest in income of consolidated subsidiaries | (28.3) | (12.1) | (67.7) | (27.5) |
| Other income net | 6.9 | 2.6 | 12.2 | 18.8 |

| | | | | |
|---|---|---|---|---|
| Income from continuing operations before income taxes | 388.1 | 213.5 | 1,058.4 | 378.9 |
| Provision for income taxes | 160.2 | 100.6 | 416.9 | 193.0 |
| Income from continuing operations | 227.9 | 112.9 | 641.5 | 185.9 |
| Income (loss) from discontinued operations | (29.9) | (6.7) | 123.6 | (23.8) |
| Net income | $ 198.0 | $ 106.2 | $ 765.1 | $ 162.1 |
| Basic earnings per common share: | | | | |
| Income from continuing operations | $ .38 | $ .19 | $ 1.07 | $ .31 |
| Income (loss) from discontinued operations | (.05) | (.01) | .21 | (.04) |
| Net income | $ .33 | $ .18 | $ 1.28 | $ .27 |
| Weighted-average shares (thousands) | 596,836 | 596,199 | 598,124 | 594,406 |
| Diluted earnings per common share: | | | | |
| Income from continuing operations | $ .38 | $ .19 | $ 1.05 | $ .31 |
| Income (loss) from discontinued operations | (.05) | (.01) | .20 | (.04) |
| Net income | $ .33 | $ .18 | $ 1.25 | $ .27 |
| Weighted-average shares (thousands) | 610,651 | 609,062 | 611,761 | 608,045 |
| Cash dividends declared per common share | $ .10 | $ .09 | $ .29 | $ .255 |

* Recast as discussed in Note 2.

See accompanying notes.

3

Table of Contents

**The Williams Companies, Inc.**
**Consolidated Balance Sheet**
**(Unaudited)**

| (Dollars in millions, except per-share amounts) | September 30, 2007 | December 31, 2006 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 1,455.4 | $ 2,268.6 |
| Restricted cash | 96.1 | 91.6 |
| Accounts and notes receivable (net of allowance of $15.2 in 2007 and $14.8 in 2006) | 955.1 | 980.8 |
| Inventories | 214.5 | 237.6 |
| Derivative assets | 1,068.3 | 1,285.5 |
| Margin deposits | 104.9 | 59.3 |
| Assets of discontinued operations | 1,907.4 | 837.3 |
| Deferred income taxes | 307.1 | 337.2 |
| Other current assets and deferred charges | 177.4 | 224.1 |
| Total current assets | 6,286.2 | 6,322.0 |
| Restricted cash | 34.3 | 34.5 |
| Investments | 884.9 | 866.0 |
| Property, plant and equipment net | 15,599.9 | 14,157.6 |
| Derivative assets | 1,355.1 | 1,844.0 |
| Goodwill | 1,011.4 | 1,011.4 |
| Assets of discontinued operations | | 564.5 |
| Other assets and deferred charges | 664.9 | 602.4 |
| Total assets | $ 25,836.7 | $ 25,402.4 |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | $ 1,020.5 | $ 906.3 |
| Accrued liabilities | 1,104.2 | 1,223.6 |
| Customer margin deposits payable | 205.5 | 128.7 |
| Derivative liabilities | 1,097.0 | 1,303.6 |
| Liabilities of discontinued operations | 1,409.9 | 739.3 |
| Long-term debt due within one year | 465.6 | 392.1 |
| Total current liabilities | 5,302.7 | 4,693.6 |
| Long-term debt | 7,424.6 | 7,622.0 |
| Deferred income taxes | 3,177.2 | 2,879.9 |
| Derivative liabilities | 1,482.4 | 1,920.2 |
| Liabilities of discontinued operations | | 146.5 |
| Other liabilities and deferred income | 900.8 | 986.2 |

| | | |
|---|---|---|
| Contingent liabilities and commitments (Note 12) | | |
| Minority interests in consolidated subsidiaries | 1,093.4 | 1,080.8 |
| Stockholders equity: | | |
| Common stock (960 million shares authorized at $1 par value; 606.1 million shares issued at September 30, 2007 and 602.8 million shares issued at December 31, 2006) | 606.1 | 602.8 |
| Capital in excess of par value | 6,717.3 | 6,605.7 |
| Accumulated deficit | (459.6) | (1,034.0) |
| Accumulated other comprehensive loss | (133.0) | (60.1) |
| | 6,730.8 | 6,114.4 |
| Less treasury stock, at cost (13.2 million shares of common stock in 2007 and 5.7 million shares in 2006) | (275.2) | (41.2) |
| Total stockholders equity | 6,455.6 | 6,073.2 |
| Total liabilities and stockholders equity | $ 25,836.7 | $ 25,402.4 |

See accompanying notes.

Table of Contents

**The Williams Companies, Inc.**
**Consolidated Statement of Cash Flows**
**(Unaudited)**

| (Dollars in millions) | Nine months ended September 30, 2007 | 2006* |
|---|---|---|
| **OPERATING ACTIVITIES:** | | |
| Net income | $ 765.1 | $ 162.1 |
| Adjustments to reconcile to net cash provided by operations: | | |
| Reclassification of deferred net hedge gains to earnings related to sale of power business | (429.3) | |
| Depreciation, depletion and amortization | 792.3 | 627.9 |
| Accrual for securities litigation settlement and related costs | | 165.3 |
| Provision for deferred income taxes | 444.7 | 119.6 |
| Provision for loss on investments, property and other assets | 136.2 | 6.2 |
| Net gain on disposition of assets | (20.2) | (13.6) |
| Early debt retirement costs | | 31.4 |
| Minority interest in income of consolidated subsidiaries | 67.7 | 27.5 |
| Amortization of stock-based awards | 58.0 | 32.5 |
| Cash provided (used) by changes in current assets and liabilities: | | |
| Accounts and notes receivable | (72.4) | 366.7 |
| Inventories | 22.9 | 12.5 |
| Margin deposits and customer margin deposits payable | 31.2 | (21.1) |
| Other current assets and deferred charges | (10.6) | (47.1) |
| Accounts payable | (2.2) | (297.9) |
| Accrued liabilities | (250.4) | (162.3) |
| Changes in current and noncurrent derivative assets and liabilities | 200.2 | 252.1 |
| Other, including changes in noncurrent assets and liabilities | (55.4) | 52.5 |
| Net cash provided by operating activities | 1,677.8 | 1,314.3 |
| **FINANCING ACTIVITIES:** | | |
| Proceeds from long-term debt | 184.4 | 699.4 |
| Payments of long-term debt | (317.6) | (773.6) |
| Proceeds from issuance of common stock | 37.4 | 21.6 |
| Proceeds from sale of limited partner units of consolidated partnership | | 225.2 |
| Tax benefit of stock-based awards | 20.7 | |
| Purchase of treasury stock | (234.0) | |
| Payments for debt issuance costs and amendment fees | (2.2) | (26.9) |
| Premiums paid on early debt retirement | (7.1) | (25.8) |
| Dividends paid | (173.9) | (151.8) |
| Dividends and distributions paid to minority interests | (57.4) | (28.1) |
| Changes in restricted cash | (4.4) | 5.0 |
| Changes in cash overdrafts | 42.9 | (17.0) |
| Other net | 3.0 | (1.3) |
| Net cash used by financing activities | (508.2) | (73.3) |

| | | |
|---|---|---|
| **INVESTING ACTIVITIES:** | | |
| Property, plant and equipment: | | |
| Capital expenditures | (2,099.9) | (1,758.9) |
| Net proceeds from dispositions | 1.0 | (10.6) |
| Proceeds from contract termination payment | | 3.3 |
| Changes in accounts payable and accrued liabilities | 33.5 | 37.8 |
| Purchases of investments/advances to affiliates | (36.9) | (45.6) |
| Purchases of auction rate securities | (304.3) | (375.8) |
| Proceeds from sales of auction rate securities | 352.5 | 319.8 |
| Proceeds from dispositions of investments and other assets | 64.6 | 51.3 |
| Other net | 6.7 | 15.1 |
| Net cash used by investing activities | (1,982.8) | (1,763.6) |
| Decrease in cash and cash equivalents | (813.2) | (522.6) |
| Cash and cash equivalents at beginning of period | 2,268.6 | 1,597.2 |
| Cash and cash equivalents at end of period | $ 1,455.4 | $ 1,074.6 |

* Revised as discussed in Note 2.

See accompanying notes.

Table of Contents

**The Williams Companies, Inc.**
**Notes to Consolidated Financial Statements**
**(Unaudited)**

## Note 1. General

Our accompanying interim consolidated financial statements do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto in Exhibit 99.1 of our Form 8-K dated October 12, 2007. The accompanying unaudited financial statements include all normal recurring adjustments that, in the opinion of our management, are necessary to present fairly our financial position at September 30, 2007, and results of operations for the three and nine months ended September 30, 2007 and 2006 and cash flows for the nine months ended September 30, 2007 and 2006.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

## Note 2. Basis of Presentation

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, the accompanying consolidated financial statements and notes reflect the results of operations and financial position of our power business as discontinued operations. (See Note 3.) These operations, which were part of our previously reported Power segment, include:

- Our 7,500-megawatt portfolio of power-related contracts being sold to Bear Energy, LP, a unit of the Bear Stearns Company, Inc. This includes tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software.

- Our natural gas-fired electric generating plant located in Hazleton, Pennsylvania (Hazleton).

We have recast all segment information in the Notes to Consolidated Financial Statements to reflect the discontinued operations noted above.

Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to our continuing operations.

Cash flows are presented without separate disclosure of discontinued operations. Amounts previously reported have been revised with no material impact. This revision did not change the total reported net cash provided or used by operating, financing, or investing activities.

We currently own approximately 22.5 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us. Williams Partners L.P. is consolidated within our Midstream Gas & Liquids (Midstream) segment in accordance with Emerging Issues Task Force (EITF) Issue No. 04-5, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights.

## Note 3. Discontinued Operations

On May 21, 2007, we announced a definitive agreement to sell substantially all of our power business to Bear Energy, LP, a unit of the Bear Stearns Company, Inc. for $512 million. Under the agreement, this amount will be reduced by net portfolio cash flows from an April 1, 2007, valuation date through the transaction closing date. Mark-to-market gains and losses between this valuation date and the close of the transaction will not impact the economic value of the sale, although they may change the recorded gain or loss on the sale as derivative assets and liabilities included in the transaction continue to be reflected at fair value. We expect the sale to close in November 2007.

Table of Contents

Notes (Continued)

In addition, we expect to sell certain remaining power assets. We have retained the exposure related to certain contingent liabilities associated with our power business. (See Note 12.) The following table outlines the impact to our previously reported Power segment.

| Previous Power Segment Component | New Presentation |
|---|---|
| Portfolio of power-related contracts, including tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software | Being sold to Bear Energy, LP and reported as discontinued operations |
| Natural gas-fired electric generating plant near Hazleton, Pennsylvania | Being marketed for sale and reported as discontinued operations |
| Marketing and risk management operations associated with managing our natural gas businesses | Retained and reported within the Gas Marketing Services segment |
| Equity investment in Aux Sable Liquid Products, LP (Aux Sable) | Retained and reported within the Midstream segment |
| Natural gas-fired electric generating plant near Bloomfield, New Mexico (Milagro facility) | Retained and reported within the Midstream segment |

***Summarized results of discontinued operations***

The following table presents the summarized results of discontinued operations for the three and nine months ended September 30, 2007 and September 30, 2006.

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| | **(Millions)** | | **(Millions)** | |
| Revenues | $ 703.2 | $ 788.2 | $ 2,210.1 | $ 1,924.0 |
| Income (loss) from discontinued operations before income taxes | (51.7) | (9.3) | 324.1 | (36.6) |
| Impairments | 2.0 | | (123.9) | |
| Benefit (provision) for income taxes | 19.8 | 2.6 | (76.6) | 12.8 |
| Income (loss) from discontinued operations | $ (29.9) | $ (6.7) | $ 123.6 | $ (23.8) |

*Income (loss) from discontinued operations before income taxes* for the nine months ended September 30, 2007, includes a gain of $429.3 million (reported in *revenues* of discontinued operations) associated with the reclassification of deferred net hedge gains from *accumulated other comprehensive income* to earnings. This reclassification was based on the determination that the forecasted transactions related to the derivative cash flow hedges being sold were probable of not occurring. (See Note 13.) The three and nine months ended September 30, 2007, include unrealized mark-to-market losses of approximately $49 million and $72 million, respectively. The nine months ended September 30, 2007, also include approximately $31 million of sale-related expenses.

*Income (loss) from discontinued operations before income taxes* for the nine months ended September 30, 2006, includes a $19.2 million charge for an adverse arbitration award related to our former chemical fertilizer business.

The *impairments* for the nine months ended September 30, 2007, include approximately $111 million related to the carrying value of certain derivative contracts for which we had previously elected the normal purchases and normal sales exception under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and, accordingly, were no longer recording at fair value and approximately $13 million related to our Hazleton facility. These impairments are based on our comparison of the carrying value to the estimated fair value less cost to sell.

Our *income from discontinued operations* will be impacted by any gain or loss to be determined later this year upon the expected closing of the transaction with Bear Energy, LP, and by operating results through the date of close.

Table of Contents

Notes (Continued)

***Summarized assets and liabilities of discontinued operations***

The following table presents the summarized assets and liabilities of discontinued operations as of September 30, 2007 and December 31, 2006.

| | September 30, 2007 | December 31, 2006 |
|---|---|---|
| | (Millions) | |
| Derivative assets | $ 631.6 | $ 592.7 |
| Accounts receivable net | 254.1 | 232.1 |
| Other current assets | 5.3 | 11.9 |
| Total current assets | 891.0 | 836.7 |
| Property, plant and equipment net | 9.1 | 23.5 |
| Derivative assets | 1,002.2 | 540.9 |
| Other noncurrent assets | 5.1 | .7 |
| Total noncurrent assets | 1,016.4 | 565.1 |
| Total assets | $ 1,907.4 | $ 1,401.8 |
| Reflected on balance sheet as: | | |
| Current assets | $ 1,907.4 | $ 837.3 |
| Noncurrent assets | | 564.5 |
| Total assets | $ 1,907.4 | $ 1,401.8 |
| Derivative liabilities | $ 479.4 | $ 479.3 |
| Other current liabilities | 216.7 | 259.7 |
| Total current liabilities | 696.1 | 739.0 |
| Derivative liabilities | 674.4 | 123.6 |
| Other noncurrent liabilities | 39.4 | 23.2 |
| Total noncurrent liabilities | 713.8 | 146.8 |
| Total liabilities | $ 1,409.9 | $ 885.8 |
| Reflected on balance sheet as: | | |
| Current liabilities | $ 1,409.9 | $ 739.3 |
| Noncurrent liabilities | | 146.5 |
| Total liabilities | $ 1,409.9 | $ 885.8 |

**Note 4. Other Accruals**

The following table presents significant gains or losses from other accruals or adjustments reflected in *other (income) expense net* within *segment costs and expenses*.

| | Three months ended September 30, 2007 | Three months ended September 30, 2006 | Nine months ended September 30, 2007 | Nine months ended September 30, 2006 |
|---|---|---|---|---|
| | (Millions) | | (Millions) | |
| **Gas Pipeline** | | | | |
| Change in estimate related to a regulatory liability | $ | $ | $ (16.6) | $ |
| Income associated with payments received for a terminated firm transportation agreement on Grays Harbor lateral. Associated with this gain is interest income of $2.3 million, which is included in *investing income* | (12.2) | | (18.2)* | |
| **Midstream** | | | | |
| Accrual for Gulf Liquids litigation contingency. Associated with this contingency is an interest accrual of $25.2 million, which is included in *interest accrued* (See Note 12) | | 2.4 | | 70.4 |

* Includes $6.0 million of income recognized in the second quarter of 2007 that was previously presented in *other income net* below *operating income.*

Table of Contents

Notes (Continued)

*Investing income* within our Other segment for the nine months ended September 30, 2007, includes $14.7 million of gains from the sales of cost-based investments.

**Note 5. Provision for Income Taxes**

The *provision for income taxes* includes:

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (Millions) | | (Millions) | |
| Current: | | | | |
| Federal | $ 7.9 | $ 5.2 | $ 4.9 | $ 17.9 |
| State | 5.7 | (.8) | 6.6 | 10.9 |
| Foreign | 12.8 | 14.6 | 37.4 | 31.8 |
| | 26.4 | 19.0 | 48.9 | 60.6 |
| Deferred: | | | | |
| Federal | 118.2 | 52.4 | 319.2 | 87.9 |
| State | 11.2 | 21.6 | 33.3 | 26.2 |
| Foreign | 4.4 | 7.6 | 15.5 | 18.3 |
| | 133.8 | 81.6 | 368.0 | 132.4 |
| Total provision | $ 160.2 | $ 100.6 | $ 416.9 | $ 193.0 |

The effective income tax rate for the three and nine months ended September 30, 2007, is greater than the federal statutory rate due primarily to the effect of state income taxes and taxes on foreign operations. The higher effective tax rate for the nine months ended September 30, 2007, was partially offset by the benefit recognized in association with a favorable private letter ruling received from the Internal Revenue Service (IRS) concerning our securities litigation settlement and fees, a portion of which were previously treated as nondeductible.

The effective income tax rate for the three months ended September 30, 2006, is greater than the federal statutory rate due primarily to the effect of state income taxes and taxes on foreign operations.

The effective income tax rate for the nine months ended September 30, 2006, is greater than the federal statutory rate due primarily to the effect of state income taxes, taxes on foreign operations, estimated nondeductible expenses associated with our securities litigation settlement and fees, and nondeductible expenses associated with the conversion of convertible debentures.

Effective January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109 (FIN 48) and, as required by the Interpretation, recognized the net impact of the cumulative effect of adoption as a $16.8 million decrease to retained earnings. The Interpretation prescribes guidance for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. To recognize a tax position, the enterprise determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. A tax position that meets the more likely than not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured as the largest amount of benefit, determined on a cumulative probability basis, that is greater than 50 percent likely of being realized upon ultimate settlement.

As of January 1, 2007, we had approximately $93 million of unrecognized tax benefits. If recognized, approximately $83 million, net of federal tax expense, would be recorded as a reduction of income tax expense. There have been no significant changes to these amounts as of September 30, 2007.

We recognize related interest and penalties as a component of income tax expense. Approximately $97 million of interest and $5 million of penalties have been accrued at January 1, 2007. Of the $97 million interest accrued, approximately $22 million relates to uncertain tax positions.

As of January 1, 2007, the IRS examination of our consolidated U.S. income tax return for 2002 was in process. During the first quarter of 2007, the IRS also commenced examination of the 2003 through 2005 consolidated U.S. income tax returns. IRS examinations for 1996 through 2001 have been completed but the years remain open while certain issues are under review with the Appeals Division of the IRS. The statute of limitations for most states expires one year after IRS audit settlement.

Notes (Continued)

Generally, tax returns for our Venezuelan and Canadian entities are open to audit from 2003 through 2006. Tax returns for our Argentine entities are open to audit from 2001 through 2006. Certain Canadian entities are currently under examination.

**Note 6. Earnings Per Common Share from Continuing Operations**

Basic and diluted earnings per common share are computed as follows:

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| | **(Dollars in millions, except per-share amounts; shares in thousands)** | | | |
| Income from continuing operations available to common stockholders for basic and diluted earnings per share (1) | $ 227.9 | $ 112.9 | $ 641.5 | $ 185.9 |
| Basic weighted-average shares | 596,836 | 596,199 | 598,124 | 594,406 |
| Effect of dilutive securities: | | | | |
| Unvested restricted stock units (2) | 1,769 | 1,032 | 1,553 | 921 |
| Stock options | 4,726 | 4,503 | 4,762 | 4,351 |
| Convertible debentures (3) | 7,320 | 7,328 | 7,322 | 8,367 |
| Diluted weighted-average shares | 610,651 | 609,062 | 611,761 | 608,045 |
| Earnings per share from continuing operations: | | | | |
| Basic | $ .38 | $ .19 | $ 1.07 | $ .31 |
| Diluted | $ .38 | $ .19 | $ 1.05 | $ .31 |

(1) The three and nine months ended September 30, 2007, and the three and nine months ended September 30, 2006, include \$.7 million, \$2.0 million, \$.7 million and \$2.3 million, respectively, of interest expense, net of tax, associated with the convertible debentures. These amounts have been added

back to *income from continuing operations available to common stockholders* to calculate diluted earnings per common share.

(2) The unvested restricted stock units outstanding at September 30, 2007, will vest over a period from November 2007 through September 2010.

(3) During January 2006, we converted approximately $220.2 million of our 5.5 percent junior subordinated convertible debentures in exchange for 20.2 million shares of common stock, a $25.8 million cash premium, and $1.5 million of accrued interest. At September 30, 2007, approximately $80 million of our convertible debentures remain outstanding.

The table below includes information related to stock options that were outstanding at September 30 of each respective year but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the third quarter weighted-average market price of our common shares.

| | September 30, 2007 | September 30, 2006 |
|---|---|---|
| Options excluded (millions) | 1.9 | 4.2 |
| Weighted-average exercise prices of options excluded | $ 37.56 | $ 35.33 |
| Exercise price ranges of options excluded | $33.51-$42.29 | $23.88-$42.29 |
| Third quarter weighted-average market price | $ 32.56 | $ 23.87 |

Table of Contents

Notes (Continued)

**Note 7. Employee Benefit Plans**

*Net periodic pension expense* and *other postretirement benefit expense* for the three and nine months ended September 30, 2007 and 2006 are as follows. We do not expect that the sale of our power business will have a significant impact on our employee benefit plans. (See Note 3.)

| | Pension Benefits | | | |
|---|---|---|---|---|
| | Three months ended September 30, | | Nine months ended September 30, | |
| | 2007 | 2006 | 2007 | 2006 |
| | (Millions) | | (Millions) | |
| Components of net periodic pension expense: | | | | |
| Service cost | $ 5.8 | $ 5.5 | $ 17.4 | $ 16.6 |
| Interest cost | 13.5 | 12.7 | 40.4 | 37.6 |
| Expected return on plan assets | (18.2) | (16.7) | (54.5) | (50.1) |
| Amortization of prior service credit | (.1) | (.1) | (.3) | (.4) |
| Amortization of net actuarial loss | 4.6 | 5.2 | 13.9 | 14.7 |
| Regulatory asset amortization (deferral) | .2 | | .5 | (.1) |
| Net periodic pension expense | $ 5.8 | $ 6.6 | $ 17.4 | $ 18.3 |

| | Other Postretirement Benefits | | | |
|---|---|---|---|---|
| | Three months ended September 30, | | Nine months ended September 30, | |
| | 2007 | 2006 | 2007 | 2006 |
| | (Millions) | | (Millions) | |
| Components of net periodic other postretirement benefit expense: | | | | |
| Service cost | $ .7 | $ .8 | $ 2.2 | $ 2.4 |
| Interest cost | 4.3 | 4.4 | 12.8 | 13.0 |
| Expected return on plan assets | (3.1) | (2.7) | (9.2) | (8.3) |
| Amortization of prior service credit | (.1) | (.1) | (.3) | (.3) |
| Regulatory asset amortization | 1.4 | 1.8 | 4.0 | 5.4 |
| Net periodic other postretirement benefit expense | $ 3.2 | $ 4.2 | $ 9.5 | $ 12.2 |

During the nine months ended September 30, 2007, we have contributed $21.2 million to our pension plans and $10.8 million to our other postretirement benefit plans. We presently anticipate making additional contributions of approximately $20 million to our pension plans in 2007 for a total of approximately $41 million. We presently anticipate making additional contributions of approximately $3 million to our other postretirement benefit plans in 2007 for a total of approximately $14 million.

**Note 8. Stock-Based Compensation**

Effective May 17, 2007, our stockholders approved a new plan that will provide common-stock-based awards going forward to both employees and nonmanagement directors. The new plan generally contains terms and provisions consistent with the previous plans. The new plan reserves 19 million shares for issuance. Awards outstanding in all prior plans remain in those plans with their respective terms and provisions. No new grants will be made from the prior plans. The new plan permits the granting of various types of awards including, but not limited to, restricted stock units and stock options. Restricted stock units are generally valued at market value on the grant date of the award and generally vest over three years. The purchase price per share for stock options generally may not be less than the market price of the underlying stock on the date of grant. Stock options generally become exercisable over a three-year period from the date of the grant and can be subject to accelerated vesting if certain future stock prices or if specific financial performance targets are achieved. Stock options generally expire 10 years after grant. At September 30, 2007, 38.8 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 18.8 million shares were available for future grants.

Additionally, on May 17, 2007, our stockholders approved an Employee Stock Purchase Plan (ESPP) which authorizes up to 2 million shares of our common stock to be available for sale under the plan. The ESPP enables eligible participants to purchase our common stock through payroll deductions not exceeding an annual amount of $15,000 per participant. The ESPP provides for offering periods during which shares may be purchased and continues until the earliest of: (1) the Board of Directors terminates the ESPP, (2) the sale of all shares available under the ESPP, or (3) the tenth anniversary of the date the Plan was approved by the stockholders. The first offering under the ESPP commenced on October 1, 2007 and will end on December 31, 2007. Subsequent offering periods will be from January through June and from July through December. Generally, all employees are eligible to

Notes (Continued)

participate in the ESPP, with the exception of executives and international employees. The number of shares eligible for an employee to purchase during each offering period is limited to 750 shares. The purchase price of the stock is 85 percent of the lower closing price of either the first or the last day of the offering period. The ESPP requires a one-year holding period before the stock can be sold.

**Note 9. Inventories**

*Inventories* at September 30, 2007 and December 31, 2006 are:

| | September 30, 2007 | December 31, 2006 |
|---|---|---|
| | (Millions) | |
| Materials, supplies and other | $ 97.2 | $ 82.1 |
| Natural gas liquids | 64.7 | 77.9 |
| Natural gas in underground storage | 52.6 | 77.6 |
| | $ 214.5 | $ 237.6 |

**Note 10. Debt and Banking Arrangements**

***Long-Term Debt***

*Revolving credit and letter of credit facilities (credit facilities)*

At September 30, 2007, no loans are outstanding under our credit facilities. Letters of credit issued under our facilities are:

| | Letters of Credit at September 30, 2007 |
|---|---|
| | (Millions) |
| $500 million unsecured credit facilities | $ 342.0 |
| $700 million unsecured credit facilities | $ 425.8 |
| $1.5 billion unsecured credit facility | $ 28.0 |

On May 9, 2007, we amended our $1.5 billion unsecured credit facility, extending the maturity date from May 1, 2009 to May 1, 2012. Applicable borrowing rates and commitment fees for investment grade credit ratings were also modified.

*Exploration & Production s credit agreement*

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Under the credit agreement, Exploration & Production is not required to post collateral as long as the value of its domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. Exploration & Production is subject to additional covenants under the credit agreement including restrictions on hedge limits, the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments, such as dividends, under certain circumstances.

*Issuances and retirements*

On April 4, 2007, Northwest Pipeline retired $175 million of 8.125 percent senior unsecured notes due 2010. Northwest Pipeline paid premiums of approximately $7.1 million in conjunction with the early debt retirement. These premiums are considered recoverable through rates and are therefore deferred as a component of *other assets and* *deferred charges* on our consolidated balance sheet, amortizing over the life of the original debt.

On April 5, 2007, Northwest Pipeline issued $185 million aggregate principal amount of 5.95 percent senior unsecured notes due 2017 to certain institutional investors in a private debt placement. In August 2007, Northwest Pipeline completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

Notes (Continued)

*Registration payment arrangements*

Under the terms of the Northwest Pipeline $185 million 5.95 percent senior unsecured notes mentioned above, Northwest Pipeline was obligated to file a registration statement for an offer to exchange the notes for a new issue of substantially identical notes registered under the Securities Act of 1933, as amended, within 180 days from closing and use its commercially reasonable efforts to cause the registration statement to be declared effective within 270 days after closing. Northwest Pipeline initiated an exchange offer on July 26, 2007, which expired on August 23, 2007. Northwest Pipeline received full participation in the exchange offer.

On June 20, 2006, Williams Partners L.P. issued $150 million aggregate principal amount of 7.5 percent senior unsecured notes in a private debt placement. On December 13, 2006, Williams Partners L.P. issued $600 million aggregate principal amount of 7.25 percent senior unsecured notes in a private debt placement. In connection with these issuances, Williams Partners L.P. entered into registration rights agreements with the initial purchasers of the senior unsecured notes. In these agreements they agreed to conduct a registered exchange offer for the senior unsecured notes or cause to become effective a shelf registration statement providing for resale of the senior unsecured notes. Williams Partners L.P. initiated exchange offers for both series on April 10, 2007. The exchange offers were completed and closed on May 11, 2007.

On December 13, 2006, Williams Partners L.P. issued approximately $350 million of common and Class B units in a private equity offering. In connection with these issuances, Williams Partners L.P. entered into a registration rights agreement with the initial purchasers whereby Williams Partners L.P. agreed to file a shelf registration statement providing for the resale of the units. Additionally, the registration rights agreement provides for the registration of common units that would be issued upon conversion of the Class B units. On May 21, 2007, Williams Partners L.P. s outstanding Class B units were converted into common units on a one-for-one basis. Williams Partners L.P. filed the shelf registration statement on January 12, 2007, and it became effective on March 13, 2007. If the shelf registration statement is unavailable for a period that exceeds an aggregate of 30 days in any 90-day period or 105 days in any 365-day period, the purchasers are entitled to receive liquidated damages. Liquidated damages are calculated as 0.25% of the Liquidated Damages Multiplier per 30-day period for the first 60 days following the 90th day, increasing by an additional 0.25% of the Liquidated Damages Multiplier per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the Liquidated Damages Multiplier per 30-day period. The Liquidated Damages Multiplier is (i) the product of $36.59 times the number of common units purchased plus (ii) the product of $35.81 times the number of Class B units purchased. We do not expect to pay any liquidated damages related to this agreement.

As of September 30, 2007, we have not accrued any liabilities for these registration payment arrangements.

## Note 11. Stockholders Equity

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. We intend to purchase shares of our stock from time to time in open-market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors. This stock-repurchase program does not have an expiration date. In third-quarter 2007, we purchased approximately 7.45 million shares for $234 million under the program at an average cost of $31.40 per share. This stock repurchase is recorded in *treasury stock* on the Consolidated Balance Sheet.

## Note 12. Contingent Liabilities and Commitments

***Rate and Regulatory Matters and Related Litigation***

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result, a portion of the revenues of these subsidiaries has been collected subject to refund. We have accrued a liability for these potential refunds as of September 30, 2007, which we believe is adequate for any refunds that may be required.

***Issues Resulting from California Energy Crisis***

Our subsidiary, Williams Power Company, Inc. (WPC), whose results of operations were included in our previously reported Power segment (see Note 3), is engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western

Notes (Continued)

states in 2000 and 2001 were challenged in various proceedings, including those before the Federal Energy Regulatory Commission (FERC). These challenges included refund proceedings, summer 2002 90-day contracts, investigations of alleged market manipulation including withholding, gas indices and other gaming of the market, new long-term power sales to the State of California that were subsequently challenged and civil litigation relating to certain of these issues. We have entered into settlements with the State of California (State Settlement), major California utilities (Utilities Settlement), and others that substantially resolved each of these issues with these parties.

As a result of a December 19, 2006 Ninth Circuit Court of Appeals decision, which the U.S. Supreme Court has agreed to review, certain contracts that WPC entered into during 2000 and 2001 may be subject to partial refunds. These contracts, under which WPC sold electricity, totaled approximately $89 million in revenue. While WPC is not a party to the cases involved in the appellate court decision under review, the buyer of electricity from WPC is a party to the cases and claims that WPC must refund to the buyer any loss it suffers due to the decision and the FERC s reconsideration of the contract terms at issue in the decision.

Certain other issues also remain open at the FERC and for other nonsettling parties.

*Refund proceedings*

Although we entered into the State Settlement and Utilities Settlement, which resolved the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, such as various California end users that did not participate in the Utilities Settlement. As a part of the Utilities Settlement, we funded escrow accounts that we anticipate will satisfy any ultimate refund determinations in favor of the nonsettling parties including interest on refund amounts that we might owe to settling and nonsettling parties. We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable totaling approximately $24 million at September 30, 2007. Collection of the interest and the payment of interest on refund amounts from the escrow accounts is subject to the conclusion of this proceeding. Therefore, we continue to participate in the FERC refund case and related proceedings. Challenges to virtually every aspect of the refund proceedings, including the refund period, were and continue to be made to the Ninth Circuit Court of Appeals and the U.S. Supreme Court. On August 2, 2006, the Ninth Circuit issued its order that largely upheld the FERC s prior rulings, but it expanded the types of transactions that were made subject to refund. This order is subject to further appeal. Because of our settlements, we do not expect that the August 2, 2006 decision will have a material impact on us. However, the final refund calculation has not been made because of the appeals and certain unclear aspects of the refund calculation process. As part of the State Settlement, an additional $45 million, previously accrued, remains to be paid to the California Attorney General (or his designee) over the next three years, with final payment of $15 million due on January 1, 2010. Upon the sale of our power business (see Note 3), which we expect to occur this year, we will accelerate the payment of the entire remaining balance on a discounted basis.

***Reporting of Natural Gas-Related Information to Trade Publications***

We disclosed on October 25, 2002, that certain of our natural gas traders had reported inaccurate information to a trade publication that published gas price indices. In 2002, we received a subpoena from a federal grand jury in northern California seeking documents related to our involvement in California markets, including our reporting to trade publications for both gas and power transactions. We have completed our response to the subpoena. Three former traders with WPC have pled guilty to manipulation of gas prices through misreporting to an industry trade periodical. One former trader has pled not guilty. In February 2006 we entered into a deferred prosecution agreement with the Department of Justice (DOJ) under which we paid $50 million. The agreement expired on May 21, 2007 and we expect no further action by the DOJ.

Civil suits based on allegations of manipulating the gas indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in:

- Class action litigation in federal court in Nevada alleging that we manipulated gas prices for direct purchasers of gas in California. On September 5, 2007, the court approved our class settlement.

- State court litigation in California brought on behalf of certain business and governmental entities who purchased gas for their use.

Table of Contents

Notes (Continued)

Class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri, Tennessee and Wisconsin brought on behalf of direct and indirect purchasers of gas in those states. The Tennessee purchasers have appealed the Tennessee state court s February 2007 dismissal of their case. The cases in the other jurisdictions have been removed and transferred to the federal court in Nevada.

It is reasonably possible that additional amounts may be necessary to resolve the remaining outstanding litigation in this area, the amount of which cannot be reasonably estimated at this time.

***Mobile Bay Expansion***

In December 2002, an administrative law judge at the FERC issued an initial decision in Transcontinental Gas Pipe Line Corporation s (Transco) 2001 general rate case which, among other things, rejected the recovery of the costs of Transco s Mobile Bay expansion project from its shippers on a rolled-in basis and found that incremental pricing for the Mobile Bay expansion project is just and reasonable. In March 2004, the FERC issued an Order on Initial Decision in which it reversed certain parts of the administrative law judge s decision and accepted Transco s proposal for rolled-in rates. Gas Marketing Services holds long-term transportation capacity on the Mobile Bay expansion project. If the FERC had adopted the decision of the administrative law judge on the pricing of the Mobile Bay expansion project and also required that the decision be implemented effective September 1, 2001, Gas Marketing Services could have been subject to surcharges of approximately $131 million, including interest, through September 30, 2007, in addition to increased costs going forward. Certain parties have filed appeals in federal court seeking to have the FERC s ruling on the rolled-in rates overturned.

***Enron Bankruptcy***

We have outstanding claims against Enron Corp. and various of its subsidiaries (collectively Enron ) related to its bankruptcy filed in December 2001. In 2002, we sold $100 million of our claims against Enron to a third party for $24.5 million. In 2003, Enron filed objections to these claims. We have resolved Enron s objections, subject to court approval. Pursuant to the sales agreement, the purchaser of the claims demanded repayment of the purchase price for the reduced portions of the claims. In February 2007, we completed a settlement with the purchaser covering any potential repayment obligations.

***Environmental Matters***

*Continuing operations*

Since 1989, our Transco subsidiary has had studies underway to test certain of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests from the U.S. Environmental Protection Agency (EPA) and state agencies regarding such potential contamination of certain of its sites. Transco has identified polychlorinated biphenyl (PCB) contamination in compressor systems, soils and related properties at certain compressor station sites. Transco has also been involved in negotiations with the EPA and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other parties concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites. The costs of any such remediation will depend upon the scope of the remediation. At September 30, 2007, we had accrued liabilities of $5 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances. Transco has been identified as a potentially responsible party at various Superfund and state waste disposal sites. Based on present volumetric estimates and other factors, we have estimated our aggregate exposure for remediation of these sites to be less than $500,000, which is included in the environmental accrual discussed above.

Beginning in the mid-1980s, our Northwest Pipeline subsidiary evaluated many of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation might be necessary. Consistent with other natural gas transmission companies, Northwest Pipeline identified PCB contamination in air compressor systems, soils and related properties at certain compressor station sites. Similarly, Northwest Pipeline identified hydrocarbon impacts at these facilities due to the former use of earthen pits and mercury contamination at certain gas metering sites. The PCBs were remediated pursuant to a Consent Decree with the EPA in the late 1980s and Northwest Pipeline conducted a voluntary clean-up of the hydrocarbon and mercury impacts in the early 1990s. In 2005, the Washington Department of Ecology required Northwest Pipeline to reevaluate its previous mercury clean-

Notes (Continued)

ups in Washington. Consequently, Northwest Pipeline is conducting additional remediation activities at certain sites to comply with Washington s current environmental standards. At September 30, 2007, we have accrued liabilities totaling approximately $7 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline s rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At September 30, 2007, we have accrued liabilities totaling approximately $6 million for these costs.

In August 2005, our subsidiary, Williams Production RMT Company, voluntarily disclosed two air permit violations to the Colorado Department of Public Health and Environment (CDPHE). To resolve the matter, we executed a Compliance Order on Consent (COC) with the CDPHE in May 2007 under which we paid a $180,000 penalty and are conducting a supplemental environmental project to upgrade our equipment.

In March 2006, the CDPHE issued a notice of violation (NOV) to Williams Production RMT Company related to our operating permit for the Rulison evaporation pond and water management facility. In August 2006, the CDPHE issued an NOV to Williams Production RMT Company related to our Grand Valley evaporation pond and water management facility located in Garfield County, Colorado, in which the CDPHE alleged that we failed to obtain a construction permit and to comply with certain provisions of our existing permit. We have settled these matters and paid an administrative penalty of $21,970 and made a supplemental environmental project payment of $87,880.

In July 2006, the CDPHE issued an NOV to Williams Production RMT Company related to operating permits for our Roan Cliffs and Hayburn gas plants in Garfield County, Colorado. We have met with the CDPHE to discuss the allegations contained in the NOV and have provided additional requested information to the agency.

On April 11, 2007, the New Mexico Environment Department s Air Quality Bureau issued an NOV to Williams Four Corners, LLC that alleged various emission and reporting violations in connection with our Lybrook gas processing plant s flare and leak detection and repair program. We are investigating the matter.

On April 16, 2007, the CDPHE issued an NOV to Williams Production RMT Company related to alleged air permit violations at the Rifle Station natural gas dehydration facility located in Garfield County, Colorado. The Rifle Station facility had been shut down prior to our receipt of the NOV and remains closed. We responded to the CDPHE s notice on May 15, 2007.

On April 27, 2007, the Wyoming Department of Environmental Quality (WDEQ) issued an NOV to Williams Production RMT Company that alleges violations of various Wyoming Pollution Discharge Elimination System permits in connection with our coal bed methane gas production facilities in the state. We are discussing the matter with the WDEQ.

In July 2001, the EPA issued a request for information on oil releases and discharges in any amount from our pipelines, pipeline systems, and pipeline facilities used in the movement of oil or petroleum products, during the period from July 1, 1998 through July 2, 2001. In November 2001, we furnished our response. In March 2004, the DOJ invited the new owner of Williams Energy Partners and Magellan Midstream Partners, L.P. (Magellan) to enter into negotiations regarding alleged violations of the Clean Water Act. With the exception of four minor release events that underwent earlier cleanup operation under state enforcement actions, our environmental indemnification obligations to Magellan were released in a 2004 buyout. We do not expect further enforcement action with respect to the four release events or two 2006 spills at our Colorado and Wyoming facilities after providing additional requested information to the DOJ.

By letter dated September 20, 2007, the EPA required our Transco subsidiary to provide information regarding natural gas compressor stations in the states of Mississippi and Alabama as part of the EPA s investigation of our compliance with the Clean Air Act. We are preparing our response.

*Former operations, including operations classified as discontinued*

In connection with the sale of certain assets and businesses, we have retained responsibility, through indemnification of the purchasers, for environmental and other liabilities existing at the time the sale was consummated, as described below.

Notes (Continued)

Agrico

In connection with the 1987 sale of the assets of Agrico Chemical Company, we agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations to the extent such costs exceed a specified amount. At September 30, 2007, we have accrued liabilities of approximately $9 million for such excess costs.

Other

At September 30, 2007, we have accrued environmental liabilities totaling approximately $19 million related primarily to our:

- Potential indemnification obligations to purchasers of our former retail petroleum and refining operations;
- Former propane marketing operations, bio-energy facilities, petroleum products and natural gas pipelines;
- Discontinued petroleum refining facilities;
- Former exploration and production and mining operations.

These costs include certain conditions at specified locations related primarily to soil and groundwater contamination and any penalty assessed on Williams Refining & Marketing, L.L.C. (Williams Refining) associated with noncompliance with the EPA s National Emission Standards for Hazardous Air Pollutants (NESHAP). In 2002, Williams Refining submitted a self-disclosure letter to the EPA indicating noncompliance with those regulations. This unintentional noncompliance occurred due to a regulatory interpretation that resulted in under-counting the total annual benzene level at Williams Refining s Memphis refinery. Also in 2002, the EPA conducted an all-media audit of the Memphis refinery. In 2006, we entered agreements totaling approximately $3 million that resolved both the government s claims against us for alleged violations and an indemnity dispute with the purchaser in connection with our 2003 sale of the Memphis refinery. On May 1, 2007, the court approved our settlement with the government, and we paid the agreed settlement amount to the government on June 14, 2007. The matter is now concluded.

In 2004, our Gulf Liquids subsidiary initiated a self-audit of all environmental conditions (air, water, and waste) at three facilities in Geismar, Sorrento, and Chalmette, Louisiana. The audit revealed numerous infractions of Louisiana environmental regulations and resulted in a Consolidated Compliance Order and Notice of Potential Penalty from the Louisiana Department of Environmental Quality (LDEQ). We agreed with the LDEQ to pay a penalty of $109,000 as a comprehensive multi-media settlement and in July 2007, the LDEQ published the proposed settlement for public review and comment.

Certain of our subsidiaries have been identified as potentially responsible parties at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws.

*Summary of environmental matters*

Actual costs incurred for these matters could be substantially greater than amounts accrued depending on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors, but the amount cannot be reasonably estimated at this time.

***Other Legal Matters***

*Will Price (formerly Quinque)*

In 2001, fourteen of our entities were named as defendants in a nationwide class action lawsuit in Kansas state court that had been pending against other defendants, generally pipeline and gathering companies, since 2000. The plaintiffs alleged that the defendants have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs and sought an

**Table of Contents**

Notes (Continued)
unspecified amount of damages. The fourth amended petition, which was filed in 2003, deleted all of our defendant entities except two Midstream subsidiaries. All remaining defendants have opposed class certification and a hearing on plaintiffs second motion to certify the class was held in April 2005. We are awaiting a decision from the court.

*Grynberg*

In 1998, the DOJ informed us that Jack Grynberg, an individual, had filed claims on behalf of himself and the federal government, in the United States District Court for the District of Colorado under the False Claims Act against us and certain of our wholly owned subsidiaries. The claims sought an unspecified amount of royalties allegedly not paid to the federal government, treble damages, a civil penalty, attorneys fees, and costs. In connection with our sales of Kern River Gas Transmission in 2002 and Texas Gas Transmission Corporation in 2003, we agreed to indemnify the purchasers for any liability relating to this claim, including legal fees. The maximum amount of future payments that we could potentially be required to pay under these indemnifications depends upon the ultimate resolution of the claim and cannot currently be determined. Grynberg had also filed claims against approximately 300 other energy companies alleging that the defendants violated the False Claims Act in connection with the measurement, royalty valuation and purchase of hydrocarbons. In 1999, the DOJ announced that it would not intervene in any of the Grynberg cases. Also in 1999, the Panel on Multi-District Litigation transferred all of these cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. Grynberg s measurement claims remained pending against us and the other defendants; the court previously dismissed Grynberg s royalty valuation claims. In May 2005, the court-appointed special master entered a report which recommended that the claims against our Gas Pipeline and Midstream subsidiaries be dismissed but upheld the claims against our Exploration & Production subsidiaries against our jurisdictional challenge. In October 2006, the District Court dismissed all claims against us and our wholly owned subsidiaries, and in November 2006, Grynberg filed his notice of appeal with the Tenth Circuit Court of Appeals.

On August 6, 2002, Jack J. Grynberg, and Celeste C. Grynberg, Trustee on Behalf of the Rachel Susan Grynberg Trust, and the Stephen Mark Grynberg Trust, served us and one of our Exploration & Production subsidiaries with a complaint in the state court in Denver, Colorado. The complaint alleges that we have used mismeasurement techniques that distort the British Thermal Unit heating content of natural gas, resulting in the alleged underpayment of royalties to Grynberg and other independent natural gas producers. The complaint also alleges that we inappropriately took deductions from the gross value of their natural gas and made other royalty valuation errors. Under various theories of relief, the plaintiff is seeking actual damages of between $2 million and $20 million based on interest rate variations and punitive damages in the amount of approximately $1.4 million. In 2004, Grynberg filed an amended complaint against one of our Exploration & Production subsidiaries. This subsidiary filed an answer in January 2005, denying liability for the damages claimed. Trial in this case was originally set for May 2006, but the parties have negotiated an agreement dismissing the measurement claims and deferring further proceedings on the royalty claims until resolution of an appeal in another case.

*Securities class actions*

Numerous shareholder class action suits were filed against us in 2002 in the United States District Court for the Northern District of Oklahoma. The majority of the suits alleged that we and co-defendants, WilTel, previously an owned subsidiary known as Williams Communications, and certain corporate officers, acted jointly and separately to inflate the stock price of both companies. WilTel was dismissed as a defendant as a result of its bankruptcy. These cases were consolidated and an order was issued requiring separate amended consolidated complaints by our equity holders and WilTel equity holders. The underwriter defendants have requested indemnification and defense from these cases. If we grant the requested indemnifications to the underwriters, any related settlement costs will not be covered by our insurance policies. We covered the cost of defending the underwriters. In 2002, the amended complaints of the WilTel securities holders and of our securities holders added numerous claims related to WPC. On February 9, 2007, the court gave its final approval to our settlement with our securities holders. We entered into indemnity agreements with certain of our insurers to ensure their timely payment related to this settlement. The carrying value of our estimated liability related to these agreements is immaterial because we believe the likelihood of any future performance is remote.

On July 6, 2007, the court granted various defendants motions for summary judgment and entered judgment for us and the other defendants in the WilTel matter. The plaintiffs filed an appeal. Any obligation of ours to the WilTel equity holders as a result of a settlement, or as a result of trial in the event of a successful appeal of the court s judgment, will not likely be covered by insurance because our insurance coverage has been fully utilized by the

18

Notes (Continued)
settlement described above. The extent of any such obligation is presently unknown and cannot be estimated, but it is reasonably possible that our exposure could materially exceed amounts accrued for this matter.

*TAPS Quality Bank*

One of our subsidiaries, Williams Alaska Petroleum, Inc. (WAPI), is actively engaged in administrative litigation being conducted jointly by the FERC and the Regulatory Commission of Alaska (RCA) concerning the Trans-Alaska Pipeline System (TAPS) Quality Bank. In 2004, the FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions, and we accrued approximately $134 million based on our computation and assessment of ultimate ruling terms that were considered probable. Our additional potential refund liability terminated on March 31, 2004, when we sold WAPI s interests in the TAPS pipeline. We subsequently accrued additional amounts for interest.

In 2006, the FERC entered its final order (FERC Final Order), which the RCA adopted, and most of the parties appealed to the D.C. Circuit Court of Appeals. ExxonMobil also filed a similar appeal in the Alaska Superior Court. A key issue pending on appeal is the limited retroactive impact of the FERC Final Order that restricts our exposure for Quality Bank adjustment refunds to periods after February 1, 2000. ExxonMobil asserts that the FERC s reliance on the Highway Reauthorization Act as the basis for limiting the retroactive effect violates, among other things, the separation of powers under the U.S. Constitution by interfering with the FERC s independent decision-making role.

On June 7, 2007, the FERC stated the Quality Bank Administrator was free to issue invoices without any further action by the FERC. The Quality Bank Administrator issued invoices on July 31, 2007. We estimate that our net obligation for these invoices could be as much as $124 million. This amount remains an estimate because not all invoices have been received directly by WAPI. Some invoices will be directed to other parties who will calculate contributions they believe WAPI owes as a result of the issuance of the Quality Bank invoices. Amounts accrued in excess of this estimated obligation will be retained pending resolution of all appeals.

*Redondo Beach taxes*

On February 5, 2005, our subsidiary WPC received a tax assessment letter, addressed to AES Redondo Beach, L.L.C. and WPC, from the city of Redondo Beach, California, in which the city asserted that approximately $33 million in back taxes and approximately $39 million in interest and penalties are owed related to natural gas used at the generating facility operated by AES Redondo Beach. Hearings were held in July 2005 and in September 2005 the tax administrator for the city issued a decision in which he found WPC jointly and severally liable with AES Redondo Beach for back taxes of approximately $36 million and interest and penalties of approximately $21 million. Both WPC and AES Redondo Beach filed notices of appeal that were heard at the city level. On December 13, 2006, the city hearing officer for the appeal of the pre-2005 amounts issued a final decision affirming WPC s utility user tax liability and reversing AES Redondo Beach s liability because the officer ruled that AES Redondo Beach is an exempt public utility. WPC appealed this decision to the Los Angeles Superior Court, and the city also appealed with respect to AES Redondo Beach. Those appeals will be heard on January 25, 2008. On April 30, 2007, WPC paid the city the protested amount of approximately $57 million in order to pursue its appeal. Despite the city hearing officer s unfavorable decision and the payment to preserve our appeal rights, we do not believe a contingent loss is probable.

The city s assessment of our liability for the periods from 1998 through December 2006 is approximately $69 million (inclusive of interest and penalties). WPC has protested all these assessments and requested hearings on them. WPC and AES Redondo Beach have also filed separate refund actions in Los Angeles Superior Court related to certain taxes paid since the initial 2005 notice of assessment. The refund actions are stayed pending the resolution of the appeals. In connection with the sale of our power business (see Note 3), we have reached an agreement-in-principle with AES Redondo Beach to settle our dispute by equally sharing, for periods prior to the closing of the sale, any ultimate tax liability including the funding of amounts previously paid under protest.

*Gulf Liquids litigation*

Gulf Liquids contracted with Gulsby Engineering Inc. (Gulsby) and Gulsby-Bay for the construction of certain gas processing plants in Louisiana. National American Insurance Company (NAICO) and American Home Assurance Company provided payment and performance bonds for the projects. Gulsby and Gulsby-Bay defaulted on the construction contracts. In the fall of 2001, the contractors, sureties, and Gulf Liquids filed multiple cases in

**Table of Contents**

Notes (Continued)
Louisiana and Texas. In January 2002, NAICO added Gulf Liquids co-venturer WPC to the suits as a third-party defendant. Gulf Liquids asserted claims against the contractors and sureties for, among other things, breach of contract requesting contractual and consequential damages from $40 million to $80 million, any of which is subject to a sharing arrangement with XL Insurance Company.

At the conclusion of the consolidated trial of the asserted contract and tort claims, the jury returned its actual damages verdict against WPC and Gulf Liquids on July 31, 2006, and its related punitive damages verdict on August 1, 2006. Based on our interpretation of the jury verdicts, we estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $25.2 million, all of which have been accrued as of September 30, 2007. In addition, we concluded that it was reasonably possible that any ultimate judgment might have included additional amounts of approximately $199 million in excess of our accrual, which primarily represented our estimate of potential punitive damage exposure under Texas law.

From May through October 2007, the court entered seven post-trial orders in the case (interlocutory orders) which, among other things, overruled the verdict award of tort and punitive damages and any damages against WPC and the plaintiffs claims for attorneys fees. If the court s final judgment incorporates these orders, we expect the judgment to only award damages against Gulf Liquids of $8.8 million in favor of Gulsby and $4.4 million in favor of Gulsby-Bay. If the anticipated judgment is upheld on appeal, our liability will be substantially less than the amount of our accrual for these matters.

*Wyoming severance taxes*

The Wyoming Department of Audit (DOA) audited the severance tax reporting for our subsidiary Williams Production RMT Company for the production years 2000 through 2002. In August 2006, the DOA assessed additional severance tax and interest for those periods of approximately $3 million. In addition, the DOA notified us of an increase in the taxable value of our interests for ad valorem tax purposes, which is estimated to result in additional taxes of approximately $2 million, including interest. We dispute the DOA s interpretation of the statutory obligation and have appealed this assessment to the Wyoming State Board of Equalization. If the DOA prevails in its interpretation of our obligation and applies the same basis of assessment to subsequent periods, it is reasonably possible that we could owe a total of approximately $24 million to $26 million in additional taxes and interest from January 1, 2003, through September 30, 2007.

*Royalty litigation*

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in Colorado state court alleging that we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of gas and extracted products, improperly charged certain expenses, and failed to refund amounts withheld in excess of ad valorem tax obligations. The plaintiffs claim that the class might be in

Notes (Continued)

excess of 500 individuals and seek an accounting and damages. The parties have agreed to stay this action in order to participate in ongoing mediation.

***Other Divestiture Indemnifications***

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided.

We sold a natural gas liquids pipeline system in 2002, and in July 2006, the purchaser of that system filed its complaint against us and our subsidiaries in state court in Houston, Texas. The purchaser alleges that we breached certain warranties under the purchase and sale agreement and seeks approximately $18.5 million in damages and our specific performance under certain guarantees. In 2006, we filed our answer to the purchaser s complaint denying all liability. We anticipate that the trial will occur in the first quarter of 2008, and our prior suit filed against the purchaser in Delaware state court is stayed pending resolution of the Texas case.

At September 30, 2007, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on results of operations in the period in which the claim is made.

In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations.

***Summary***

Litigation, arbitration, regulatory matters, and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, will not have a materially adverse effect upon our future financial position.

***Commitments***

WPC has entered into certain contracts giving it the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are currently in operation throughout the continental United States. At September 30, 2007, WPC s estimated committed payments under these contracts range from approximately $410 million to $425 million annually through 2017 and decline over the remaining five years to $59 million in 2022. Total committed payments under these contracts over the next sixteen years are approximately $5.2 billion. These contracts are included in the pending sale of our power business to Bear Energy, LP. (See Note 3.)

***Guarantees***

In connection with agreements executed prior to our acquisition of Transco to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transco entered into certain settlements with producers which may require the indemnification of certain claims for additional royalties that the producers may be required to pay as a result of such settlements. Transco, through its agent, Gas Marketing Services, continues to purchase gas under contracts which extend, in some cases, through the life of the associated gas reserves. Certain of these contracts contain royalty indemnification provisions that have no carrying value. Producers have received certain demands and may receive other demands, which could result in claims pursuant to royalty indemnification provisions. Indemnification for royalties will depend on, among other things, the specific lease provisions between the producer and the lessor and the terms of the agreement between the producer and Transco. Consequently, the potential maximum future payments under such indemnification provisions cannot be determined. However, management believes that the probability of material payments is remote.

Table of Contents

Notes (Continued)

In connection with the 1993 public offering of units in the Williams Coal Seam Gas Royalty Trust (Royalty Trust), our Exploration & Production segment entered into a gas purchase contract for the purchase of natural gas in which the Royalty Trust holds a net profits interest. Under this agreement, we guarantee a minimum purchase price that the Royalty Trust will realize in the calculation of its net profits interest. We have an annual option to discontinue this minimum purchase price guarantee and pay solely based on an index price. The maximum potential future exposure associated with this guarantee is not determinable because it is dependent upon natural gas prices and production volumes. No amounts have been accrued for this contingent obligation as the index price continues to substantially exceed the minimum purchase price.

We are required by certain foreign lenders to ensure that the interest rates received by them under various loan agreements are not reduced by taxes by providing for the reimbursement of any domestic taxes required to be paid by the foreign lender. The maximum potential amount of future payments under these indemnifications is based on the related borrowings. These indemnifications generally continue indefinitely unless limited by the underlying tax regulations and have no carrying value. We have never been called upon to perform under these indemnifications.

We have guaranteed commercial letters of credit totaling $20 million on behalf of a certain entity in which we have an equity ownership interest. These expire by January 2008 and have no carrying value.

We have provided guarantees on behalf of certain entities in which we have an equity ownership interest. These generally guarantee operating performance measures and the maximum potential future exposure cannot be determined. There are no expiration dates associated with these guarantees. No amounts have been accrued at September 30, 2007.

We have provided guarantees in the event of nonpayment by our previously owned communications subsidiary, WilTel, on certain lease performance obligations that extend through 2042. The maximum potential exposure is approximately $44 million at September 30, 2007. Our exposure declines systematically throughout the remaining term of WilTel s obligations. The carrying value of these guarantees is approximately $40 million at September 30, 2007.

Former managing directors of Gulf Liquids are involved in litigation related to the construction of gas processing plants. Gulf Liquids has indemnity obligations to the former managing directors for legal fees and potential losses that may result from this litigation. Claims against these former managing directors have been settled and dismissed after payments on their behalf by directors and officers insurers. Some unresolved issues remain between us and these insurers, but no amounts have been accrued for any potential liability.

We have guaranteed the performance of a former subsidiary of our wholly owned subsidiary MAPCO Inc., under a coal supply contract. This guarantee was granted by MAPCO Inc. upon the sale of its former subsidiary to a third-party in 1996. The guaranteed contract provides for an annual supply of a minimum of 2.25 million tons of coal. Our potential exposure is dependent on the difference between current market prices of coal and the pricing terms of the contract, both of which are variable, and the remaining term of the contract. Given the variability of the terms, the maximum future potential payments cannot be determined. We believe that our likelihood of performance under this guarantee is remote. In the event we are required to perform, we are fully indemnified by the purchaser of MAPCO Inc. s former subsidiary. This guarantee expires in December 2010 and has no carrying value.

Table of Contents

Notes (Continued)

**Note 13. Comprehensive Income**

*Comprehensive income* is as follows:

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (Millions) | | (Millions) | |
| Net income | $ 198.0 | $ 106.2 | $ 765.1 | $ 162.1 |
| Other comprehensive income (loss): | | | | |
| Net unrealized gains on derivative instruments | 131.3 | 130.7 | 252.5 | 364.9 |
| Net reclassification into earnings of derivative instrument (gains) losses | (31.5) | 77.5 | (475.4) | 211.8 |
| Foreign currency translation adjustments | 24.3 | .4 | 55.8 | 10.7 |
| Minimum pension liability adjustment | | | | (.3) |
| Pension benefits: | | | | |
| Amortization of prior service credit | (.1) | | (.3) | |
| Amortization of net actuarial loss | 4.7 | | 13.8 | |
| Other postretirement benefits: | | | | |
| Amortization of prior service cost | .3 | | .8 | |
| Other comprehensive income (loss) before taxes | 129.0 | 208.6 | (152.8) | 587.1 |
| Income tax benefit (provision) on other comprehensive income (loss) | (40.0) | (79.7) | 79.9 | (220.6) |
| Other comprehensive income (loss) | 89.0 | 128.9 | (72.9) | 366.5 |
| Comprehensive income | $ 287.0 | $ 235.1 | $ 692.2 | $ 528.6 |

During second-quarter 2007, in anticipation of signing a definitive agreement to sell our power business (see Note 3), we concluded that certain power and gas hedged forecasted transactions were no longer probable of occurring and therefore discontinued hedge accounting prospectively and began recognizing changes in fair value directly in earnings.

We subsequently concluded that the completion of the sale of our power business was probable and therefore we concluded that it was probable that certain related forecasted transactions designated as the hedged items in cash flow hedges would not occur. We therefore recognized in our second-quarter 2007 earnings $429.3 million (reflected in *net reclassification into earnings of derivative instruments (gains) losses)* of net unrealized hedge gains which were previously deferred in *accumulated other comprehensive income*. For the nine months ended September 30, 2007, this amount is reported in *income (loss) from discontinued operations*. (See Note 3.)

*Net unrealized gains on derivative instruments* represent changes in the fair value of certain derivative contracts that have been designated as cash flow hedges. The net unrealized gains for the three months ending September 30, 2007, include:

Net unrealized gains on forward natural gas purchases and sales of approximately $132 million;

Net unrealized losses on forward natural gas liquids sales of approximately $1 million.

The net unrealized gains for the three months ending September 30, 2006, include:

Net unrealized gains on forward natural gas purchases and sales of approximately $101 million;

Net unrealized gains on forward power purchases and sales of approximately $19 million;

Net unrealized gains on forward natural gas liquids sales of approximately $11 million.

The net unrealized gains for the nine months ending September 30, 2007, include:

Net unrealized gains on forward natural gas purchases and sales of approximately $284 million;

Net unrealized losses on forward power purchases and sales of approximately $31 million;

**Table of Contents**

Notes (Continued)

Net unrealized losses on forward natural gas liquids sales of approximately $1 million.

The net unrealized gains for the nine months ending September 30, 2006, include:

Net unrealized gains on forward natural gas purchases and sales of approximately $261 million;

Net unrealized gains on forward power purchases and sales of approximately $114 million;

Net unrealized losses on forward natural gas liquids sales of approximately $10 million.

As of September 30, 2007, there are no remaining unrealized hedge gains or losses related to forward power purchases and sales deferred in *accumulated other comprehensive income.*

Our Midstream segment sells natural gas liquids produced by our processing plants. To reduce the exposure to changes in market prices, we have entered into natural gas liquids swap agreements or forward contracts to fix the prices of a limited portion of our anticipated sales of natural gas liquids. These cash flow hedges are expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item.

**Note 14. Segment Disclosures**

On May 21, 2007, we announced that we had entered into a definitive agreement to sell substantially all of our power business to Bear Energy, LP. This pending sale has impacted our segment presentation. See Notes 2 and 3 for further discussion.

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies and industry knowledge. Our master limited partnership, Williams Partners L.P., is consolidated within our Midstream segment. (See Note 2.) Other primarily consists of corporate operations.

***Performance Measurement***

We currently evaluate performance based upon *segment profit (loss)* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses*, *depreciation, depletion and amortization*, *equity earnings* and *income from investments* including impairments related to investments accounted for under the equity method. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

The majority of energy commodity hedging by certain of our business units is done through intercompany derivatives with our Gas Marketing Services segment which, in turn, enters into offsetting derivative contracts with unrelated third parties. Gas Marketing Services bears the counterparty performance risks associated with unrelated third parties. However, beginning in the first quarter of 2007, hedges related to Exploration & Production may be entered into directly between Exploration & Production and third parties under its new credit agreement. (See Note 10.)

The Gas Marketing Services segment includes the continued marketing and risk management operations that support our natural gas businesses. The operations include marketing and hedging the gas produced by Exploration & Production and procuring fuel and shrink gas for Midstream. In addition, Gas Marketing Services manages various natural gas-related contracts such as transportation, storage, and related hedges.

External revenues of our Exploration & Production segment include third-party oil and gas sales, which are more than offset by transportation expenses and royalties due third parties on intersegment sales.

Table of Contents

Notes (Continued)

The following tables reflect the reconciliation of *segment revenues* and *segment profit (loss)* to *revenues* and *operating income* as reported in the Consolidated Statement of Income.

| | Exploration & Production | Gas Pipeline | Midstream Gas & Liquids | Gas Marketing Services (Millions) | Other | Eliminations | Total |
|---|---|---|---|---|---|---|---|
| ***Three months ended September 30, 2007*** | | | | | | | |
| Segment revenues: | | | | | | | |
| External | $ (20.0) | $ 385.3 | $ 1,350.6 | $ 1,141.2 | $ 3.0 | $ | $ 2,860.1 |
| Internal | 519.3 | 7.5 | 10.3 | 105.7 | 3.5 | (646.3) | |
| Total revenues | $ 499.3 | $ 392.8 | $ 1,360.9 | $ 1,246.9 | $ 6.5 | $ (646.3) | $ 2,860.1 |
| Segment profit (loss) | $ 168.5 | $ 182.9 | $ 299.9 | $ (66.8) | $ .4 | $ | $ 584.9 |
| Less: | | | | | | | |
| Equity earnings | 10.1 | 21.0 | 20.3 | | | | 51.4 |
| Segment operating income (loss) | $ 158.4 | $ 161.9 | $ 279.6 | $ (66.8) | $ .4 | $ | 533.5 |
| General corporate expenses | | | | | | | (40.2) |
| Total operating income | | | | | | | $ 493.3 |
| ***Three months ended September 30, 2006*** | | | | | | | |
| Segment revenues: | | | | | | | |
| External | $ (54.5) | $ 331.6 | $ 1,110.9 | $ 1,121.5 | $ 2.3 | $ | $ 2,511.8 |
| Internal | 425.6 | 2.6 | 16.1 | 199.1 | 4.1 | (647.5) | |
| Total revenues | $ 371.1 | $ 334.2 | $ 1,127.0 | $ 1,320.6 | $ 6.4 | $ (647.5) | $ 2,511.8 |
| Segment profit (loss) | $ 144.5 | $ 109.0 | $ 222.5 | $ (75.7) | $ (3.4) | $ | $ 396.9 |
| Less: | | | | | | | |
| Equity earnings | 5.6 | 9.2 | 14.9 | | .2 | | 29.9 |
| Income from investments | | .5 | | | | | .5 |
| Segment operating income (loss) | $ 138.9 | $ 99.3 | $ 207.6 | $ (75.7) | $ (3.6) | $ | 366.5 |
| General corporate expenses | | | | | | | (35.0) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Securities litigation settlement and related costs | | | | | | | (3.4) |
| Total operating income | | | | | | | $ 328.1 |

| | Exploration & Production | Gas Pipeline | Midstream Gas & Liquids | Gas Marketing Services (Millions) | Other | Eliminations | Total |
|---|---|---|---|---|---|---|---|
| ***Nine months ended September 30, 2007*** | | | | | | | |
| Segment revenues: | | | | | | | |
| External | $ (96.1) | $ 1,156.0 | $ 3,573.5 | $ 3,410.6 | $ 7.8 | $ | $ 8,051.8 |
| Internal | 1,617.6 | 22.4 | 32.0 | 518.0 | 12.0 | (2,202.0) | |
| Total revenues | $ 1,521.5 | $ 1,178.4 | $ 3,605.5 | $ 3,928.6 | $ 19.8 | $ (2,202.0) | $ 8,051.8 |
| Segment profit (loss) | $ 566.0 | $ 512.9 | $ 704.6 | $ (160.1) | $ .3 | $ | $ 1,623.7 |
| Less: | | | | | | | |
| Equity earnings | 20.3 | 39.6 | 35.7 | | | | 95.6 |
| Segment operating income (loss) | $ 545.7 | $ 473.3 | $ 668.9 | $ (160.1) | $ .3 | $ | 1,528.1 |
| General corporate expenses | | | | | | | (115.8) |
| Total operating income | | | | | | | $ 1,412.3 |
| ***Nine months ended September 30, 2006*** | | | | | | | |
| Segment revenues: | | | | | | | |
| External | $ (149.9) | $ 995.9 | $ 3,116.8 | $ 3,148.5 | $ 7.3 | $ | $ 7,118.6 |
| Internal | 1,219.3 | 9.6 | 51.6 | 712.8 | 12.5 | (2,005.8) | |
| Total revenues | $ 1,069.4 | $ 1,005.5 | $ 3,168.4 | $ 3,861.3 | $ 19.8 | $ (2,005.8) | $ 7,118.6 |
| Segment profit (loss) | $ 411.9 | $ 366.4 | $ 508.2 | $ (165.0) | $ (10.2) | $ | $ 1,111.3 |
| Less: | | | | | | | |
| Equity earnings | 16.5 | 27.4 | 31.1 | | .2 | | 75.2 |
| Segment operating income (loss) | $ 395.4 | $ 339.0 | $ 477.1 | $ (165.0) | $ (10.4) | $ | 1,036.1 |
| General corporate expenses | | | | | | | (99.3) |

| | |
|---|---|
| Securities litigation settlement and related costs | (165.3) |
| Total operating income | $ 771.5 |

25

**Table of Contents**

Notes (Continued)

The following table reflects *total assets* by reporting segment.

| | Total Assets | |
|---|---|---|
| | September 30, 2007 | December 31, 2006 |
| | (Millions) | |
| Exploration & Production | $ 8,575.6 | $ 7,850.9 |
| Gas Pipeline | 8,638.6 | 8,331.7 |
| Midstream Gas & Liquids (1) | 6,366.4 | 5,561.9 |
| Gas Marketing Services | 4,813.6 | 5,519.1 |
| Other | 3,169.0 | 3,924.1 |
| Eliminations | (7,633.9) | (7,187.1) |
| | 23,929.3 | 24,000.6 |
| Assets of discontinued operations | 1,907.4 | 1,401.8 |
| Total | $ 25,836.7 | $ 25,402.4 |

(1) Total assets for our Midstream segment as of September 30, 2007, include an increase to the balance of *property, plant and equipment net* of approximately $49 million. The increase relates to additional costs of asset retirement obligations for certain gulf assets. *Other liabilities and deferred income* was increased by the same amount.

**Note 15. Recent Accounting Standards**

In September 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements (SFAS No. 157). This Statement establishes a framework for fair value measurements in the financial statements by providing a definition of fair value, provides guidance on the methods used to estimate fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after

November 15, 2007, and is generally applied prospectively. We are currently assessing the impact of SFAS No. 157 on our Consolidated Financial Statements.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115 (SFAS No. 159). SFAS No. 159 establishes a fair value option permitting entities to elect the option to measure eligible financial instruments and certain other items at fair value on specified election dates. Unrealized gains and losses on items for which the fair value option has been elected will be reported in earnings. The fair value option may be applied on an instrument-by-instrument basis, with a few exceptions, is irrevocable and is applied only to entire instruments and not to portions of instruments. SFAS No. 159 is effective as of the beginning of the first fiscal year beginning after November 15, 2007, and should not be applied retrospectively to fiscal years beginning prior to the effective date. On the adoption date, an entity may elect the fair value option for eligible items existing at that date and the adjustment for the initial remeasurement of those items to fair value should be reported as a cumulative effect adjustment to the opening balance of retained earnings. We continue to assess whether to apply the provisions of SFAS No. 159 to eligible financial instruments in place on the adoption date and the related impact on our Consolidated Financial Statements.

In April 2007, the FASB issued a Staff Position (FSP) on a previously issued FASB Interpretation (FIN). FSP FIN 39-1, Amendment of FASB Interpretation No. 39. FSP FIN 39-1 amends FIN 39, Offsetting of Amounts Related to Certain Contracts (as amended) by addressing offsetting fair value amounts recognized for the right to reclaim or obligation to return cash collateral arising from derivative instruments that have been offset pursuant to a master netting arrangement. The FSP requires disclosure of the accounting policy related to offsetting fair value amounts as well as disclosure of amounts recognized for the right to reclaim or obligation to return cash collateral. This FSP is effective for fiscal years beginning after November 15, 2007, with early application permitted, and is applied retrospectively as a change in accounting principle for all financial statements presented. We will assess the impact of FSP FIN 39-1 on our Consolidated Financial Statements.

In June 2007, the FASB ratified Emerging Issues Task Force (EITF) Issue No. 06-11 Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards (EITF 06-11). EITF 06-11 addresses the accounting for income tax benefits received on dividends paid to employees holding equity-classified nonvested shares when the dividends or dividend equivalents are charged to retained earnings pursuant to SFAS No. 123(R). This EITF should be applied prospectively to income tax benefits related to dividends declared on equity classified employee share-based payment awards in fiscal years beginning after December 15, 2007, and interim periods within those years. Early adoption is permitted as of the beginning of a fiscal year for which neither interim nor annual financial

**Table of Contents**



statements have been published. Retrospective application is prohibited. EITF 06-11 requires the disclosure of any change in accounting policy for income tax benefits of dividends on share-based payment awards as a result of adoption. We will assess the impact of EITF 06-11 on our Consolidated Financial Statements.

Table of Contents

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

**Company Outlook**

Our plan for 2007 is focused on continued disciplined growth and reducing business risk. Objectives of this plan include:

- Continue to improve both EVA® and segment profit;
- Invest in our natural gas businesses in a way that improves EVA®, meets customer needs, and enhances our competitive position;
- Continue to increase natural gas production and reserves;
- Increase the scale of our gathering and processing business in key growth basins;
- Successfully resolving the rate cases for both Northwest Pipeline and Transco.

Potential risks and/or obstacles that could prevent us from achieving these objectives include:

- Volatility of commodity prices;
- Lower than expected levels of cash flow from operations;
- Decreased drilling success at Exploration & Production;
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 12 of Notes to Consolidated Financial Statements);
- General economic and industry downturn.

We continue to address these risks through utilization of commodity hedging strategies, focused efforts to resolve regulatory issues and litigation claims, disciplined investment strategies, and maintaining our desired level of at least $1 billion in liquidity from cash and cash equivalents and unused revolving credit facilities.

Our *income from continuing operations* for the nine months ended September 30, 2007 increased $455.6 million compared to the nine months ended September 30, 2006. This result is reflective of:

- Increased operating income at Exploration & Production associated with increased production volumes and higher average net realized prices;
- Increased operating income at Gas Pipeline due primarily to new rates that went into effect during the first quarter of 2007;
- Increased operating income at Midstream due primarily to increased natural gas liquid (NGL) margins;
- The absence of 2006 litigation expense associated with shareholder lawsuits and Gulf Liquids litigation.

Natural gas prices in the Rocky Mountain areas (Rockies) have trended lower throughout 2007 due to strong drilling activities increasing third-party supplies while constrained by limited pipeline capacity. This trend has benefited Midstream as the lower regional gas prices have contributed to increased NGL margins in the West region. Exploration & Production has continued to utilize firm transportation contracts, which allow a substantial portion of their Rockies production to be sold at more advantageous market points, and basin-level collars and fixed-price hedges to reduce exposure to this trend.

See additional discussion in Results of Operations.

Management s Discussion and Analysis (Continued)

Our *net cash provided by operating activities* for the nine months ended September 30, 2007, increased $363.5 million compared to the nine months ended September 30, 2006, primarily due to an increase in our operating results.

**Recent Events**

During third quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to become a publicly traded master limited partnership that will own and operate natural gas transportation and storage assets. On September 12, 2007, WMZ filed a registration statement on Form S-1 with the Securities and Exchange Commission (SEC) relating to a proposed underwritten initial public offering of 13 million common units, representing limited partner interests, plus an option for the underwriters to purchase up to an additional 1.95 million common units. On October 29, 2007, Williams Pipeline Partners L.P. filed an amendment to the registration statement. A subsidiary of ours will serve as the general partner of WMZ. The initial asset of the new partnership will be a 25 percent interest in Northwest Pipeline GP, formerly Northwest Pipeline Corporation.

On August 2, 2007, we announced that Transco and its customers have reached a settlement-in-principle on all substantive issues in Transco s pending 2006 rate case. Final resolution of the rate case is subject to the filing of a formal stipulation and agreement, which we expect to file in the fourth quarter of 2007, and subsequent approval by the FERC.

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. We intend to purchase shares of our stock from time to time in open market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors. This stock-repurchase program does not have an expiration date. Through the end of the third quarter, we have repurchased approximately 7.45 million shares for $234 million at an average cost of $31.40 per share. We are funding this program with cash on hand.

On May 21, 2007, we announced our intent to sell substantially all of our power business to Bear Energy, LP, a unit of the Bear Stearns Company, Inc. for $512 million. This sale reduces the risk and complexity of our overall business model and allows our ongoing efforts to focus our investment capital and growth efforts on our core natural gas businesses. The sale is expected to close in November 2007. See further discussion below.

In April 2007, our Board of Directors approved a regular quarterly dividend of 10 cents per share, which reflects an increase of 11 percent compared to the 9 cents per share that we paid in each of the four prior quarters and marks the fourth increase in our dividend since late 2004.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the pending rate case for Northwest Pipeline. The settlement establishes an increase in general system firm transportation rates on Northwest Pipeline s system from $0.30760 to $0.40984 per Dth (dekatherm), effective January 1, 2007.

**General**

Unless indicated otherwise, the following discussion and analysis of Results of Operations and Financial Condition relates to our current continuing operations and should be read in conjunction with the Consolidated Financial Statements and notes thereto included in Item 1 of this document and Exhibit 99.1 of our Form 8-K dated October 12, 2007, that reflects our power business as a discontinued operation.

**Sale of Power Business**

The pending sale of our power business to Bear Energy, LP, includes tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software. Our natural gas-fired electric generating plant located in Hazleton, Pennsylvania (Hazleton), is currently being marketed for sale. These operations are part of our previously reported Power segment and are now reflected in our results of operations as discontinued operations. (See Notes 2 and 3 of Notes to Consolidated Financial Statements.)

Based on management s conclusion that completion of the sale to Bear Energy, LP, is probable, we recognized in second-quarter 2007 earnings of $429.3 million related to unrealized net hedge gains which were previously deferred in *accumulated other comprehensive income*. This was based on the determination that the forecasted transactions related to certain derivative cash flow hedges being sold were probable of not occurring. We also

Management s Discussion and Analysis (Continued)

recorded second-quarter 2007 impairments of approximately $111 million related to the carrying value of certain derivative contracts for which we had previously elected the normal purchases and normal sales exception under SFAS 133 and, accordingly, were no longer recording at fair value and approximately $15 million related to Hazleton. These impairments are based on our comparison of the carrying value to the estimated fair value less cost to sell.

Our *income from discontinued operations* will be impacted by any gain or loss to be determined later this year upon the expected closing of the transaction with Bear Energy, LP, and by operating results through the date of close.

We have received approvals from the Federal Energy Regulatory Commission and the Federal Trade Commission, and certain required counterparty consents. Certain other conditions remain to be satisfied prior to closing of the sale, which we expect to occur in November 2007.

Other continuing components of our former Power segment are now being reported as follows:

Marketing and risk management operations that support our natural gas businesses are reflected in the Gas Marketing Services segment.

Our equity investment in Aux Sable Liquid Products, LP (Aux Sable) is now reported within the Midstream segment.

Our natural gas-fired electric generating plant near Bloomfield, New Mexico (Milagro facility), is now reported within the Midstream segment.

Additionally, our Gas Marketing Services segment may be negatively impacted by the results of exiting or liquidating certain legacy natural gas contracts that were formerly part of our Power segment.

## Results of Operations

### *Consolidated Overview*

The following table and discussion is a summary of our consolidated results of operations for the three and nine months ended September 30, 2007, compared to the three and nine months ended September 30, 2006. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

| | Three months ended September 30, | | | | Nine months ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2006 | $ Change from 2006 | % Change from 2006* | 2007 | 2006 | $ Change from 2006 | % Change from 2006* |
| | (Millions) | | | | (Millions) | | | |
| Revenues | $ 2,860.1 | $ 2,511.8 | +348.3 | +14% | $ 8,051.8 | $ 7,118.6 | +933.2 | +13% |
| Costs and expenses: | | | | | | | | |
| Costs and operating expenses | 2,221.3 | 2,039.6 | -181.7 | -9% | 6,244.8 | 5,778.9 | -465.9 | -8% |
| Selling, general and administrative expenses | 107.8 | 113.0 | +5.2 | +5% | 317.3 | 266.6 | -50.7 | -19% |
| Other (income) expense net | (2.5) | (7.3) | -4.8 | -66% | (38.4) | 37.0 | +75.4 | NM |
| General corporate expenses | 40.2 | 35.0 | -5.2 | -15% | 115.8 | 99.3 | -16.5 | -17% |
| Securities litigation settlement and related costs | | 3.4 | +3.4 | +100% | | 165.3 | +165.3 | +100% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Total costs and expenses | 2,366.8 | 2,183.7 | | | 6,639.5 | 6,347.1 | | |
| Operating income | 493.3 | 328.1 | | | 1,412.3 | 771.5 | | |
| Interest accrued net | (161.6) | (156.2) | -5.4 | -3% | (494.1) | (490.4) | -3.7 | -1% |
| Investing income | 77.8 | 51.1 | +26.7 | +52% | 195.7 | 137.9 | +57.8 | +42% |
| Early debt retirement costs | | | | | | (31.4) | +31.4 | +100% |
| Minority interest in income of consolidated subsidiaries | (28.3) | (12.1) | -16.2 | -134% | (67.7) | (27.5) | -40.2 | -146% |
| Other income net | 6.9 | 2.6 | +4.3 | +165% | 12.2 | 18.8 | -6.6 | -35% |
| Income from continuing operations before income taxes | 388.1 | 213.5 | | | 1,058.4 | 378.9 | | |
| Provision for income taxes | 160.2 | 100.6 | -59.6 | -59% | 416.9 | 193.0 | -223.9 | -116% |
| Income from continuing operations | 227.9 | 112.9 | | | 641.5 | 185.9 | | |
| Income (loss) from discontinued operations | (29.9) | (6.7) | -23.2 | NM | 123.6 | (23.8) | +147.4 | NM |
| Net income | $ 198.0 | $ 106.2 | | | $ 765.1 | $ 162.1 | | |

* + = Favorable change to *net income*; - = Unfavorable change to *net income*; NM = A percentage calculation is not meaningful due to change in signs or a percentage change greater than 200.

Management s Discussion and Analysis (Continued)

*Three months ended September 30, 2007 vs. three months ended September 30, 2006*

The increase in *revenues* is due primarily to higher Midstream revenues due to increases associated with our olefins production business, NGL and olefins marketing revenues and production of NGLs. Additionally, Exploration & Production experienced higher revenues due to an increase in production volumes and net realized average prices. Gas Pipeline revenues increased due to increased rates in effect since the first quarter of 2007.

The increase in *costs and operating expenses* is due primarily to increased costs associated with our olefins production business and increased NGL and olefin marketing purchases at Midstream. Additionally, Exploration & Production experienced higher depreciation, depletion and amortization and lease operating expenses due primarily to higher production volumes.

*Other (income) expense net,* within *operating income* in third-quarter 2007 includes:

Income of $12.2 million associated with a payment received for a terminated firm transportation agreement on Gas Pipeline s Grays Harbor lateral;

A gain of approximately $4 million related to deferred consideration received on a 2005 asset sale at Midstream;

Losses of approximately $7 million on retirements, write-downs and the abandonment of certain assets at Midstream;

Net losses of approximately $6 million on foreign currency exchanges at Midstream.

*Other (income) expense net,* within *operating income* in third-quarter 2006 includes gains on sales of assets of $8 million at Midstream, partially offset by losses on asset retirements of $5 million at Midstream primarily due to the impact of accelerating the timing of abandonment.

The increase in *general corporate expenses* is primarily due to increased charitable contributions.

The increase in *operating income* reflects continued strong natural gas production growth at Exploration & Production, record high NGL margins at Midstream, and the positive effect of new rates at Gas Pipeline.

The increase in *interest accrued net* is due primarily to changes in our debt portfolio, most significantly the issuance of new debt in December 2006 by Williams Partners L.P., our consolidated master limited partnership.

The increase in *investing income* is due primarily to increased equity earnings at Gas Pipeline, Exploration & Production, and Midstream.

*Minority interest* in income of consolidated subsidiaries increased primarily due to the growth in the minority interest holdings of Williams Partners L.P.

*Provision for income taxes* increased due primarily to increased pre-tax income in 2007 as compared to 2006. The effective income tax rate for the three months ended September 30, 2007 and 2006, is greater than the federal statutory rate due primarily to the effect of state income taxes and taxes on foreign operations.

The increase in *loss from discontinued operations* is primarily due to higher operating losses related to our discontinued power business in the three months ended September 30, 2007 compared to the three months ended September 30, 2006, in addition to $17 million of pre-tax sale-related expenses recorded in the third quarter of 2007. (See Note 3 of Notes to Consolidated Financial Statements.) This increase is partially offset by the absence of a $3.7 million net-of-tax charge in the three months ended September 30, 2006 associated with a loss contingency related to a former exploration business.

*Nine months ended September 30, 2007 vs. nine months ended September 30, 200*6

The increase in *revenues* is due primarily to higher Exploration & Production revenues due to an increase in production volumes and net realized average prices and in gas management activities related to gas purchased on behalf of certain outside parties, which are offset by a similar increase in *costs and operating expenses*. Additionally, Midstream experienced increases associated with NGL and olefins marketing revenues and with production of NGLs and olefins. Gas Pipeline revenues also increased due to increased rates in effect since the first quarter of 2007.

**Table of Contents**

Management s Discussion and Analysis (Continued)

The increase in *costs and operating expenses* is due primarily to increased NGL and olefin marketing purchases and increased costs associated with our olefins production business at Midstream. Additionally, Exploration & Production experienced higher depreciation, depletion and amortization and lease operating expenses due primarily to higher production volumes, as well as higher expenses for gas management expenses related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *revenues*.

The increase in *selling, general and administrative expenses (SG&A)* is primarily due to increased staffing in support of increased drilling and operational activity at Exploration & Production and the absence of a $24.8 million gain in 2006 relating to the sale of certain receivables at Gas Marketing Services.

*Other (income) expense net* within *operating income* in 2007 includes:

Income of $18.2 million associated with payments received for a terminated firm transportation agreement on Gas Pipeline s Grays Harbor lateral;

Income of $16.6 million associated with a change in estimate related to a regulatory liability at Northwest Pipeline;

Income of approximately $8 million due to the reversal of a planned major maintenance accrual at Midstream;

A gain of approximately $4 million related to deferred consideration received on a 2005 asset sale at Midstream;

Losses of approximately $7 million on retirements, write-downs and the abandonment of certain assets at Midstream.

*Other (income) expense net* within *operating income* in 2006 includes:

A $70.4 million accrual for a Gulf Liquids litigation contingency (see Note 12 of Notes to Consolidated Financial Statements);

Losses on asset retirements of $5 million at Midstream previously discussed;

Income of $9 million due to a settlement of an international contract dispute at Midstream;

Gains on sales of properties of $8 million at Midstream previously discussed;

An approximate $4 million gain on sale of idle gas treating equipment at Midstream;

An approximate $4 million favorable transportation settlement at Midstream.

The increase in *general corporate expenses* is attributable to various factors, including higher information technology, employee-related costs, and charitable contributions.

The *securities litigation settlement and related costs* is the result of our settlement related to class-action securities litigation filed on behalf of purchasers of our securities between July 24, 2000 and July 22, 2002. (See Note 12 of Notes to Consolidated Financial Statements.)

The increase in *operating income* reflects continued strong natural gas production growth at Exploration & Production, record high NGL margins at Midstream, the positive effect of new rates at Gas Pipeline, and the absence of 2006 litigation expense associated with shareholder lawsuits and Gulf Liquids Litigation

The increase in *interest accrued net* is due primarily to the changes in our debt portfolio previously discussed, partially offset by the absence of $20.6 million in 2006 interest expense associated with our Gulf Liquids litigation contingency.

*Investing income* increased primarily due to increased interest income of approximately $28 million primarily associated with larger cash and cash equivalent balances combined with higher rates of return in 2007 compared to

2006, increased equity earnings of approximately $20 million at Gas Pipeline, Exploration & Production and Midstream and approximately $14.7 million of gains from sales of cost-based investments in 2007. Partially



---

Management s Discussion and Analysis (Continued)
offsetting these items is the absence of an approximate $7 million gain on the sale of an international investment in 2006.

*Early debt retirement costs* in 2006 includes $25.8 million in premiums and $1.2 million in fees related to the January 2006 debt conversion and $4.4 million of accelerated amortization of debt expenses related to the retirement of the debt secured by assets of Williams Production RMT Company.

*Minority interest* in income of consolidated subsidiaries increased primarily due to the growth in the minority interest holdings of Williams Partners L.P.

*Provision for income taxes* increased due primarily to increased pre-tax income. The effective income tax rate for the nine months ended September 30, 2007, is greater than the federal statutory rate due primarily to the effect of state income taxes and taxes on foreign operations. The higher effective tax rate was partially offset by the benefit recognized in association with a favorable private letter ruling received from the Internal Revenue Service (IRS) concerning our securities litigation settlement and fees, a portion of which were previously treated as nondeductible. The effective income tax rate for the nine months ended September 30, 2006, is greater than the federal statutory rate due primarily to the effect of state income taxes, taxes on foreign operations, estimated nondeductible expenses associated with securities litigation, and nondeductible expenses associated with the conversion of convertible debentures.

*Income (loss) from discontinued operations* in 2007 includes a pre-tax gain of $429.3 million associated with the reclassification of deferred net hedge gains from *accumulated other comprehensive income* related to our discontinued power business, offset by a $111 million pre-tax charge to impair the carrying value of certain derivative contracts for which we had previously elected the normal purchases and normal sales exception under SFAS 133 and, accordingly, were no longer recording at fair value, a $13 million pre-tax impairment charge for our Hazelton facility and $31 million of pre-tax sale-related expenses. Also, $76 million in pre-tax operating losses related to our discontinued power business are included. *Loss from discontinued operations* in 2006 includes a $11.9 million net-of-tax arbitration charge related to our former chemical fertilizer business, $8.6 million net-of-tax in operating losses related to our discontinued power business, and a $3.7 million net-of-tax charge associated with a loss contingency related to a former exploration business. (See Note 3 of Notes to Consolidated Financial Statements.)

Management s Discussion and Analysis (Continued)

**Results of Operations Segments**

**Exploration & Production**

***Overview of Nine Months Ended September 30, 2007***

During the first nine months of 2007, we continued our strategy of a rapid execution of our development drilling program in our growth basins. Accordingly, we:

Increased average daily domestic production levels by approximately 22 percent compared to the first nine months of 2006. The average daily domestic production for the first nine months was approximately 890 million cubic feet of gas equivalent (MMcfe) in 2007 compared to 727 MMcfe in 2006. The increased production is primarily due to increased development within the Piceance, Powder River, and Fort Worth basins.

Benefited from increased domestic net realized average prices, which increased by approximately 16 percent compared to the first nine months of 2006. The domestic net realized average price for the first nine months was $5.09 per thousand cubic feet of gas equivalent (Mcfe) in 2007 compared to $4.38 per Mcfe in 2006. Net realized average prices include market prices, net of fuel and shrink and hedge positions, less gathering and transportation expenses.

Increased capital expenditures for domestic drilling, development, and acquisition activity in the first nine months of 2007 by approximately $215 million compared to 2006.

The benefits of higher production volumes and higher net realized average prices were partially offset by increased operating costs. The increase in operating costs was primarily due to increased production volumes and higher well service and industry costs.

*Significant events*

In February 2007, we entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Margin requirements, if any, under this new facility are dependent on the level of hedging and on natural gas reserves value. (See Note 10 of Notes to Consolidated Financial Statements.)

We may also execute hedges with the Gas Marketing Services segment, which, in turn, executes offsetting derivative contracts with unrelated third parties. In this situation, Gas Marketing Services, generally, bears the counterparty performance risks associated with unrelated third parties. Hedging decisions primarily are made considering our overall commodity risk exposure and are not executed independently by Exploration & Production.

During the first nine months of 2007, we entered into various derivative collar agreements at the basin level which, in the aggregate, hedge an additional 215 million cubic feet of gas (MMcf) per day for production in the first quarter of 2008, 155 MMcf per day for production in the second quarter through fourth quarter of 2008, and 205 MMcf per day for production in 2009.

In May and July 2007, we increased our position in the Fort Worth basin by acquiring producing properties and leasehold acreage for approximately $41 million. These acquisitions are consistent with our growth strategy of leveraging our horizontal drilling expertise by acquiring and developing low-risk properties in the Barnett Shale formation. In July 2007, we increased our position in the Piceance basin by acquiring additional undeveloped leasehold acreage and producing properties for approximately $36 million.

***Outlook for the Remainder of 2007***

Our expectations for the remainder of the year include:

Maintaining our development drilling program in our key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth through our remaining planned capital expenditures projected between $305 million and $405 million.

**Table of Contents**

Management s Discussion and Analysis (Continued)

- Continuing to grow our average daily domestic production level with a goal of 10 to 20 percent annual growth compared to 2006.

Natural gas prices in the Rocky Mountain areas have trended lower throughout 2007 due to strong drilling activities increasing supplies while constrained by limited pipeline capacity. However, we continue to utilize firm transportation contracts which allow a substantial portion of our Rockies production to be sold at more advantageous market points. Our continued use of basin-level collars and fixed-price hedges has also reduced our exposure to this trend.

Approximately 171 MMcf of our forecasted 2007 daily production is hedged by NYMEX and basis fixed-price contracts at prices that average $4.16 per thousand cubic feet of gas (Mcf) at a basin level. In addition, we have collar agreements for each month remaining in 2007 as follows:

- NYMEX collar agreement for approximately 15 MMcf per day at a floor price of $6.50 per Mcf and a ceiling price of $8.25 per Mcf.

- Northwest Pipeline/Rockies collar agreement for approximately 50 MMcf per day at a floor price of $5.65 per Mcf and a ceiling price of $7.45 per Mcf at a basin level.

- El Paso/San Juan collar agreements totaling approximately 130 MMcf per day at a weighted-average floor price of $5.98 per Mcf and a weighted-average ceiling price of $9.63 per Mcf at a basin level.

- Mid-Continent (PEPL) collar agreements totaling approximately 78 MMcf per day at a weighted-average floor price of $6.82 per Mcf and a weighted-average ceiling price of $10.73 per Mcf at a basin level.

Risks to achieving our expectations include weather conditions at certain of our locations, costs of services associated with drilling, and market price movements.

***Period-Over-Period Results***

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (Millions) | | (Millions) | |
| Segment revenues | $ 499.3 | $ 371.1 | $ 1,521.5 | $ 1,069.4 |
| Segment profit | $ 168.5 | $ 144.5 | $ 566.0 | $ 411.9 |

*Three months ended September 30, 2007 vs. three months ended September 30, 2006*

Total *segment revenues* increased $128.2 million, or 35 percent, primarily due to the following:

- $83 million, or 26 percent, increase in domestic production revenues reflecting $59 million associated with a 19 percent increase in production volumes sold and $24 million associated with a 7 percent increase in net realized average prices. The increase in production volumes reflects an increase in the number of producing wells primarily from the Piceance and Powder River basins. Net realized average prices include market prices, net of fuel and shrink and hedge positions, less gathering and transportation expenses. The impact of hedge positions on increased net realized average prices includes both the expiration of a portion of fixed-price hedges that are lower than the current market prices and higher than current market prices related to basin-specific collars entered into during the period;

- $29 million increase in revenues for gas management activities related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *segment costs and expenses*;

- $6 million increase in unrealized gains from hedge ineffectiveness.

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative forward sales contracts that fix the sales price relating to a portion of our future production. Approximately 19 percent of domestic production in the third quarter of 2007 was hedged by NYMEX and basis fixed-price contracts

**Table of Contents**

Management s Discussion and Analysis (Continued)

at a weighted-average price of $3.75 per Mcf at a basin level compared to 39 percent hedged at a weighted-average price of $3.80 per Mcf for the same period in 2006. Also in the third quarter of 2007, approximately 29 percent of domestic production was hedged in the collar agreements previously discussed in the Outlook section compared to 15 percent hedged in various collar agreements in the third quarter of 2006.

Total *segment costs and expenses* increased $109 million, primarily due to the following:

$43 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;

$29 million increase in expenses for gas management activities related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *segment revenues*;

$15 million higher lease operating expenses from the increased number of producing wells primarily within the Piceance basin in combination with higher well service expenses, facility expenses, equipment rentals, maintenance and repair services, and salt water disposal expenses;

$7 million higher *SG&A expenses* primarily due to increased staffing in support of increased drilling and operational activity including higher compensation.

The $24.0 million increase in s*egment profit* is primarily due to the 19 percent increase in domestic production volumes sold as well as the 7 percent increase in net realized average prices, partially offset by the increase in *segment costs and expenses*.

*Nine months ended September 30, 2007 vs. nine months ended September 30, 2006*

Total *segment revenues* increased $452.1 million, or 42 percent, primarily due to the following:

$370 million, or 42 percent, increase in domestic production revenues reflecting $201 million higher revenues associated with a 22 percent increase in production volumes sold and $169 million higher revenues associated with a 16 percent increase in net realized average prices. The increase in production volumes primarily reflects an increase in the number of producing wells, primarily in the Piceance and Powder River basins. The higher net realized average prices reflect the benefit of higher average market prices for natural gas in the first nine months of 2007 compared to 2006. The impact of hedge positions on increased net realized average prices includes both the expiration of a portion of fixed-price hedges that are lower than the current market prices and higher than current market prices related to basin-specific collars entered into during the period;

$91 million increase in revenues for gas management activities related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *segment costs and expenses*;

Partially offset by a $12 million decrease in unrealized gains from hedge ineffectiveness.

Total *segment costs and expenses* increased $302 million, primarily due to the following:

$131 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;

$91 million increase in expenses for gas management activities related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *segment revenues*;

$34 million higher lease operating expenses primarily due to the increased number of producing wells primarily within the Piceance basin combined with higher well service expenses, facility expenses, equipment rentals, maintenance and repair services, and salt water disposal expenses;

$25 million higher *SG&A expenses* primarily due to increased staffing in support of increased drilling and operational activity including higher compensation. In addition, we incurred higher insurance and information technology support costs related to the increased activity. First quarter 2007 also includes approximately $5 million of expenses associated with a correction of costs incorrectly capitalized in prior periods;

Table of Contents



- $7 million higher operating taxes primarily due to higher average market prices and production volumes sold;

- $6 million higher exploration expenses primarily due to undeveloped lease amortization.

The $154.1 million increase in s*egment profit* is primarily due to the 22 percent increase in domestic production volumes sold as well as the 16 percent increase in net realized average prices, partially offset by the increase in *segment costs and expenses*.

**Gas Pipeline**

***Overview of Nine Months Ended September 30, 2007***

*Gas Pipeline master limited partnership*

On September 12, 2007, Williams Pipeline Partners L.P. filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of common units representing limited partner interests. Williams Pipeline Partners L.P. anticipates offering 13 million common units, plus an option for the underwriters to purchase up to an additional 1.95 million common units. On October 29, 2007, Williams Pipeline Partners L.P. filed and amendment to the registration statement.

Williams Pipeline Partners L.P. was formed to own and operate natural gas transportation and storage assets. The initial asset of the new partnership will be a 25 percent interest in Northwest Pipeline GP, formerly Northwest Pipeline Corporation. In conjunction with the new master limited partnership, Northwest Pipeline Corporation was converted to a partnership and renamed Northwest Pipeline GP (Northwest Pipeline), effective October 1, 2007. We will continue to own the remaining interest and will continue to operate Northwest Pipeline GP.

*Status of rate cases*

During 2006, Northwest Pipeline and Transco each filed general rate cases with the FERC for increases in rates. The new rates are effective, subject to refund, on January 1, 2007, for Northwest Pipeline and on March 1, 2007, for Transco. We expect the new rates to result in significantly higher revenues.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the pending rate case for Northwest Pipeline. The settlement establishes an increase in general system firm transportation rates on Northwest Pipeline s system from $0.30760 to $0.40984 per Dth (dekatherm), effective January 1, 2007.

On August 2, 2007, we announced that Transco and its customers have reached a settlement-in-principle on all substantive issues in Transco s pending 2006 rate case. Final resolution of the rate case is subject to the filing of a formal stipulation and agreement, which we expect to file in the fourth quarter of 2007, and subsequent approval by the FERC.

*Parachute Lateral project*

In August 2006, we received FERC approval to construct a 37.6-mile expansion that will provide additional natural gas transportation capacity in northwest Colorado. The planned expansion will increase capacity by 450 thousand Dth per day (Mdt/d) through the 30-inch diameter line at a cost of approximately $86 million. The expansion was placed into service in May 2007.

***Outlook for the Remainder of 2007***

*Leidy to Long Island expansion project*

We are expanding Transco s natural gas pipeline in the northeast United States. The estimated cost of the project is approximately $163 million. The expansion will provide 100 Mdt/d of incremental firm capacity and is expected to be in service in December 2007.

Table of Contents

Management s Discussion and Analysis (Continued)

*Potomac expansion project*

We are expanding Transco s existing facilities in the Mid-Atlantic region of the United States by constructing 16.4 miles of 42-inch pipeline. The project will provide 165 Mdt/d of incremental firm capacity. The estimated cost of the project is approximately $88 million, with an anticipated in-service date of November 2007.

***Period-Over-Period Results***

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (Millions) | | (Millions) | |
| Segment revenues | $ 392.8 | $ 334.2 | $ 1,178.4 | $ 1,005.5 |
| Segment profit | $ 182.9 | $ 109.0 | $ 512.9 | $ 366.4 |

*Three months ended September 30, 2007 vs. three months ended September 30, 2006*

*Revenues* increased $58.6 million, or 18 percent, due primarily to a $51 million increase in transportation revenue and a $7 million increase in storage revenue resulting primarily from new rates effective in the first quarter of 2007. In addition, revenues increased $13 million due primarily to the sale of excess inventory gas. The gain on the sale of excess inventory gas has been deferred pending approval by the FERC. Partially offsetting these increases is a $12 million decrease in revenue due to exchange imbalance settlements (offset in *costs and operating expenses*).

*Costs and operating expenses* increased $11 million, or 6 percent, due primarily to:

An increase of $13 million in costs associated with the sale of excess inventory gas which includes a $5 million deferred gain pending FERC approval;

An increase in depreciation expense of $9 million due to property additions.

Partially offsetting these increases is a decrease in costs of $12 million associated with exchange imbalance settlements (offset in *revenues*).

*SG&A expenses* decreased $9 million, or 19 percent, due primarily to a $3 million decrease in property insurance expenses resulting from a decrease in premiums and a $3 million decrease in personnel costs.

*Other (income) expense net* changed favorably by $6 million due primarily to $12.2 million of income associated with a payment received for a terminated firm transportation agreement on Northwest Pipeline s Grays Harbor lateral, partially offset by $7 million of expense related to higher asset retirement obligations.

Equity earnings increased $11.8 million due primarily to a $10 million increase in Gulfstream equity earnings. The increase in Gulfstream equity earnings is due to improved operating results and includes our proportionate share of approximately $4 million related to the reduction of previously expensed costs associated with Gulfstream s Phase IV expansion project, which were capitalized in third quarter 2007 upon receiving FERC approval of the project.

The $73.9 million, or 68 percent, increase in *segment profit* is due primarily to $58.6 million higher revenues, $9 million lower *SG&A expenses,* $11.8 million higher equity earnings and $6 million favorable *other (income) expense net* as previously discussed. Partially offsetting these favorable changes are higher *costs and operating expenses* as previously discussed.

*Nine months ended September 30, 2007 vs. nine months ended September 30, 2006*

*Revenues* increased $172.9 million, or 17 percent, due primarily to a $127 million increase in transportation revenue and a $17 million increase in storage revenue resulting primarily from new rates effective in the first quarter of 2007. In addition, revenues increased $37 million due primarily to the sale of excess inventory gas. The gain on the sale of excess inventory gas has been deferred pending approval by the FERC. Partially offsetting these increases is a $12 million decrease in revenue due to exchange imbalance settlements (offset in *costs and operating expenses*).

Management s Discussion and Analysis (Continued)

*Costs and operating expenses* increased $60 million, or 11 percent, due primarily to:

- An increase of $37 million in costs associated with the sale of excess inventory gas which includes a $14 million deferred gain pending FERC approval;

- An increase in depreciation expense of $24 million due to property additions;

- An increase in personnel costs of $8 million;

- The absence of a $3 million credit to expense recorded in 2006 related to corrections of the carrying value of certain liabilities.

Partially offsetting these increases is a decrease in costs of $12 million associated with exchange imbalance settlements (offset in *revenues*).

*SG&A expenses* decreased $2 million, or 2 percent, due primarily to a $5 million decrease in expense related to an adjustment to correct rent expense from prior periods partially offset by a $3 million increase in property insurance.

*Other (income) expense net* changed favorably by $20 million due primarily to $18.2 million of income associated with payments received for a terminated firm transportation agreement on Northwest Pipeline s Grays Harbor lateral. This amount includes approximately $6 million of income recognized in the second quarter of 2007 that was previously presented within *other income (expense) net* below *operating income*. Also included in the favorable change is $16.6 million of income recorded in the second quarter of 2007 for a change in estimate related to a regulatory liability at Northwest Pipeline, partially offset by $14 million of expense related to higher asset retirement obligations.

Equity earnings increased $12.2 million due primarily to a $13 million increase in Gulfstream equity earnings resulting from improved operating results.

The $146.5 million, or 40 percent, increase in *segment profit* is due primarily to $172.9 million higher revenues, $20 million favorable *other (income) expense net* and $12.2 million higher equity earnings as previously discussed. Partially offsetting these increases are higher *costs and operating expenses* as previously discussed.

**Midstream Gas & Liquids**

***Overview of Nine Months Ended September 30, 2007***

Midstream s ongoing strategy is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. Our business is focused on consistently attracting new business by providing highly reliable service to our customers.

Significant events during the first nine months of 2007 include the following:

*Continued favorable commodity price margins*

The actual average realized natural gas liquid (NGL) per unit margins at our processing plants during the third quarter of 2007 was a record high 62 cents per gallon. NGL margins exceeded Midstream s rolling five-year average for the first nine months of 2007. The geographic diversification of Midstream assets contributed significantly to our actual realized unit margins resulting in margins generally greater than that of the industry benchmarks for gas processed in the Henry Hub area and fractionated and sold at Mont Belvieu. The largest impact was realized at our western United States gas processing plants, which benefited from lower regional market natural gas prices.

Table of Contents

Management s Discussion and Analysis (Continued)

**Domestic Gathering and Processing Per Unit NGL Margin with Production and Sales Volumes by Quarter (excludes partially owned plants)**

*Expansion efforts in growth areas*

Consistent with our strategy, we continued to expand our midstream operations where we have large-scale assets in growth basins.

During the first quarter of 2007, we completed construction at our existing gas processing complex located near Opal, Wyoming, to add a fifth cryogenic gas processing train capable of processing up to 350 MMcf/d, bringing total Opal capacity to approximately 1,450 MMcf/d. This plant expansion became operational during the first quarter. We also have several expansion projects ongoing in the West region to lower field pressures and increase production volumes for our customers who continue robust drilling activities in the region.

During 2007, we have continued pre-construction activities on the Perdido Norte project which includes oil and gas lines that would expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico. In addition, we completed agreements with certain producers to provide gathering, processing and transportation services over the life of the reserves. We also intend to expand our Markham gas processing facility to adequately serve this new gas production. The scale of the project has increased to include additional pipeline and processing capacity and is now estimated to cost approximately $545 million and be in service in the third quarter of 2009.

In March 2007, we announced plans to construct and operate a 450 MMcf/d natural gas processing plant in western Colorado s Piceance basin, where Exploration & Production has its most significant volume of natural gas production, reserves and development activity. Exploration & Production s existing Piceance basin processing plants are primarily designed to condition the natural gas to meet quality specifications for pipeline transmission, not to maximize the extraction of NGLs. We expect the new Willow Creek facility to recover 25,000 barrels per day of NGLs at startup, which is expected to be in the third quarter of 2009.

In June 2007, Williams Partners L.P. completed its acquisition of our 20 percent interest in Discovery Producer Service, LLC (Discovery). Williams Partners L.P. now owns a 60 percent interest in Discovery.

In July 2007, we exercised our right of first refusal to acquire BASF s 5/12th ownership interest in the Geismar olefins facility for approximately $62 million. The acquisition increases our total ownership to 10/12th.

**Table of Contents**

Management s Discussion and Analysis (Continued)

***Outlook***

The following factors could impact our business for the remainder of 2007 and beyond.

As evidenced in recent years, natural gas and crude oil markets are highly volatile. NGL margins earned at our gas processing plants in the last six quarters were above our rolling five-year average, due to global economics maintaining high crude prices which correlate to strong NGL prices in relationship to natural gas prices. Forecasted domestic demand for ethylene and propylene, along with political instability in many of the key oil producing countries, currently support NGL margins continuing to exceed our rolling five-year average. Natural gas prices in the Rocky Mountain areas have trended lower throughout 2007 due to strong drilling activities increasing supplies while third-party production volumes have been constrained by limited pipeline capacity. The construction of a new third-party pipeline slated to transport gas from the Rocky Mountain areas in the beginning of 2008 would indicate increasing natural gas prices, moderating our expected future NGL margins. We expect 2008 NGL margins to be below 2007 NGL margins. As part of our efforts to manage commodity price risks on an enterprise basis, we continue to evaluate our commodity hedging strategies.

Margins in our olefins business are highly dependent upon continued economic growth within the United States and any significant slow down in the economy would reduce the demand for the petrochemical products we produce in both Canada and the United States. Based on recent market price forecasts and our increased ownership in our Geismar facility, we anticipate results from our olefins business to be above 2006 levels.

Gathering and processing fee revenues in our West region in 2007 are expected to be at or slightly above levels of previous years due to continued strong drilling activities in our core basins.

Fee revenues in our Gulf Coast region in 2007 are expected to be below levels of previous years due to declining volumes. Fee revenues include gathering, processing, production handling and transportation fees. We expect fee revenues in our Gulf Coast region to increase in 2008 as we expand our Devil s Tower infrastructure to serve the Blind Faith and Bass Lite prospects.

Revenues from deepwater production areas are often subject to risks associated with the interruption and timing of product flows which can be influenced by weather and other third-party operational issues.

We will continue to invest in facilities in the growth basins in which we provide services. We expect continued expansion of our gathering and processing systems in our Gulf Coast and West regions to keep pace with increased demand for our services. As we pursue these activities, our operating and general and administrative expenses are expected to increase.

We expect continued expansion in the deepwater areas of the Gulf of Mexico to contribute to our future segment revenues and segment profit. We expect these additional fee-based revenues to lower our proportionate exposure to commodity price risks.

We continued construction of 37-mile extensions of both of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect located in Mississippi Canyon. These extensions, originally estimated to cost approximately $200 million, are expected to be ready for service by the second quarter of 2008. Heavy loop currents in the eastern Gulf of Mexico during the second quarter of 2007 caused some delays and contributed to increasing the total estimated project cost to approximately $250 million. These loop currents have now subsided slightly, allowing construction to resume. The extensions are still expected to be ready for service by the second quarter of 2008.

We are continuing efforts with our customer in Venezuela to resolve approximately $20 million in past due invoices, before associated reserves, related to labor escalation charges. The customer is not disputing the index used to calculate these charges and we have calculated the charges according to the terms of the contract. The customer does, however, believe the index has resulted in an inequitable escalation over time. While we believe the receivables, net of associated reserves, are collectible, our negotiations may not be successful, potentially leading to default in various project agreements and a write-off of the remaining amounts.

Table of Contents

Management s Discussion and Analysis (Continued)

The Venezuelan government continues its public criticism of U.S. economic and political policy, has implemented unilateral changes to existing energy related contracts, and has expropriated privately held assets within the energy and telecommunications sector, escalating our concern regarding political risk in Venezuela.

Our right of way agreement with the Jicarilla Apache Nation (JAN), which covered certain gathering system assets in Rio Arriba County of northern New Mexico, expired on December 31, 2006. We currently operate our gathering assets on the JAN lands pursuant to a special business license granted by the JAN which expires December 31, 2007. We are engaged in discussions with the JAN designed to result in the sale of our gathering assets which are located on or are isolated by the JAN lands. Provided the parties are able to reach an acceptable value on the sale of the subject gathering assets, our expectation is that we will nonetheless maintain partial revenues associated with gathering and processing downstream of the JAN lands and continue to operate the gathering assets on the JAN lands for an undetermined period of time beyond December 31, 2007. Based on current estimated gathering volumes and range of annual average commodity prices over the past five years, we estimate that gas produced on or isolated by the JAN lands represents approximately $20 million to $30 million of the West region s annual gathering and processing revenue less related product costs.

***Period-Over-Period Results***

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (Millions) | | (Millions) | |
| Segment revenues | $ 1,360.9 | $ 1,127.0 | $ 3,605.5 | $ 3,168.4 |
| Segment profit (loss) | | | | |
| *Domestic gathering & processing* | 251.0 | 184.0 | 586.1 | 482.0 |
| *Venezuela* | 22.4 | 22.5 | 77.9 | 80.0 |
| *Other* | 48.0 | 36.8 | 102.3 | (3.8) |
| *Indirect general and administrative expense* | (21.5) | (20.8) | (61.7) | (50.0) |
| Total | $ 299.9 | $ 222.5 | $ 704.6 | $ 508.2 |

In order to provide additional clarity, our management s discussion and analysis of operating results separately reflects the portion of general and administrative expense not allocated to an asset group as *indirect general and administrative expense*. These charges represent any overhead cost not directly attributable to one of the specific asset groups noted in this discussion.

*Three months ended September 30, 2007 vs. three months ended September 30, 2006*

The $233.9 million increase in *segment revenues* is largely due to a $111 million increase in revenues from our olefins production business, a $92 million increase in the revenues from the marketing of NGLs and olefins, and a $50 million increase in revenues associated with the production of NGLs, partially offset by a $14 million decrease in fee revenues.

*Segment costs and expenses* increased $162 million primarily as a result of a $98 million increase in costs from our olefins production business, an $85 million increase in NGL and olefin marketing purchases, and the absence of $8 million gains on the sales of assets in 2006. These increases are partially offset by a $33 million decrease in costs associated with the production of NGLs due primarily to lower natural gas prices, and a $4 million gain in 2007 resulting from deferred consideration received on the sale of an olefins fractionator and the related pipeline system in the Gulf in 2005.

The $77.4 million increase in Midstream s *segment profit* primarily reflects $83 million higher NGL margins, $13 million higher margins from our olefins production business, $7 million higher NGL and olefin marketing margins, and the $4 million gain in 2007, partially offset by $14 million lower fee revenues, and the absence of

$8 million gains on the sales of assets in 2006. A more detailed analysis of the segment profit of Midstream s various operations is presented as follows.

Domestic gathering & processing

The $67 million increase in *domestic gathering and processing segment profit* includes an $80 million increase in the West region, partially offset by a $13 million decrease in the Gulf Coast region.

The $80 million increase in the West region s *segment profit* primarily results from $83 million in higher NGL margins. This increase was driven by a decrease in costs associated with the production of NGLs reflecting lower natural gas prices, an increase in average per unit NGL prices, and higher volumes due primarily to new capacity on the fifth cryogenic train at our Opal plant. NGL margins are defined as NGL revenues less BTU replacement cost, plant fuel, transportation and fractionation expense.

Management s Discussion and Analysis (Continued)

The $13 million decrease in the Gulf Coast region s *segment profit* is primarily a result of $11 million lower fee revenues from our deepwater assets due primarily to declines in producers volumes and the absence of $8 million gains on the sale of certain gathering assets and a processing plant in July 2006. These decreases are partially offset by $4 million lower operating expenses due primarily to the absence of property damage repair costs incurred in 2006.

Venezuela

*Segment profit* for our Venezuela assets is comparable to the prior period.

Other

The $11.2 million increase in *segment profit* of our other operations is due primarily to $13 million in higher margins from our olefins production business primarily resulting from the increase in ownership of the Geismar olefins facility in July 2007, $7 million higher margins related to the marketing of olefins and NGLs, and a $4 million gain in 2007 resulting from deferred consideration received on the sale of a olefins fractionator and the related pipeline system in the Gulf in 2005. These increases were partially offset by $8 million in higher foreign exchange losses related to the revaluation of current assets held in U.S. dollars within our Canadian operations and $4 million higher maintenance expenses due primarily to the increase in ownership of the Geismar facility.

Indirect general and administrative expense

Indirect general and administrative expense is comparable to the prior period.

*Nine months ended September 30, 2007 vs. nine months ended September 30, 2006*

The $437.1 million increase in *segment revenues* is largely due to a $269 million increase in revenues from the marketing of NGLs and olefins, a $138 million increase in revenues from our olefins production business, and a $72 million increase in revenues associated with the production of NGLs, partially offset by a $24 million decrease in fee revenues.

*Segment costs and expenses* increased $245 million primarily as a result of a $246 million increase in NGL and olefin marketing purchases, a $118 million increase in costs from our olefins production business, a $28 million increase in operating expenses including higher depreciation, treating plant fuel and a gas imbalance revaluation loss in the current year compared to gains in the prior year, the absence of $12 million gains on the sales of assets in 2006, and $8 million higher general and administrative expenses. These increases are partially offset by the absence of a 2006 charge of $70.4 million related to our Gulf Liquids litigation, a $91 million decrease in costs associated with the production of NGLs due primarily to lower natural gas prices, and a $4 million gain in 2007 resulting from deferred consideration received on the sale of an olefins fractionator and the related pipeline system in the Gulf in 2005.

The $196.4 million increase in Midstream s *segment profit* reflects $163 million higher NGL margins, the absence of the previously mentioned $70.4 million Gulf Liquids litigation charge in 2006, $23 million higher NGL and olefin marketing margins, $20 million higher margins from our olefins production business, and the $4 million gain in 2007. These were partially offset by $33 million in production handling and gathering volume declines from our deepwater assets, $28 million in higher operating expenses, the absence of $12 million gains on the sales of assets in 2006, and $8 million higher general and administrative expenses. A more detailed analysis of the segment profit of Midstream s various operations is presented as follows.

Domestic gathering & processing

The $104.1 million increase in *domestic gathering and processing segment profit* includes a $161 million increase in the West region, partially offset by a $57 million decrease in the Gulf Coast region.

**Table of Contents**

Management s Discussion and Analysis (Continued)

The $161 million increase in our West region s *segment profit* primarily results from higher NGL margins and higher processing fee based revenues, partially offset by higher operating expenses. The significant components of this increase include the following:

NGL margins increased $182 million in the first nine months of 2007 compared to the same period in 2006. This increase was driven by a decrease in costs associated with the production of NGLs reflecting lower natural gas prices, higher volumes due primarily to new capacity on the fifth cryogenic train at our Opal plant and an increase in average per unit NGL prices.

Processing fee revenues increased $10 million. Processing volumes are higher due to customers electing to take liquids and pay processing fees.

Operating expenses increased $14 million including $7 million in higher depreciation, $7 million related to gas imbalance revaluation losses in the current year compared to gains in the prior year, and $5 million in higher treating plant and gathering fuel due primarily to the expiration of a favorable gas purchase contract. These were partially offset by the absence of a $7 million accounts payable accrual adjustment in 2006 and $4 million in higher system gains.

The absence of $4 million in gains on the sales of certain gathering assets in the first quarter of 2006.

The $57 million decrease in the Gulf Coast region s *segment profit* is primarily a result of lower volumes from our deepwater facilities, lower NGL margins, and the absence of gains on the sales of assets in 2006. The significant components of this decrease include the following:

Fee revenues from our deepwater assets decreased $33 million due primarily to declines in producers volumes.

NGL margins decreased $19 million driven by lower NGL recoveries and an increase in costs associated with the production of NGLs, partially offset by higher NGL prices.

The absence of $8 million in gains on the sales of certain gathering assets and a processing plant in July 2006.

Venezuela

*Segment profit* for our Venezuela assets decreased $2.1 million. The decrease is primarily due to the absence of a $9 million gain from the settlement of a contract dispute in 2006 and a $10 million decline in operating results, partially offset by $15 million of higher currency exchange gains. The decline in operating margin is largely due to $5 million lower fee revenues due primarily to the discontinuance in 2007 of revenue recognition related to labor escalation charges and $6 million higher operating expenses.

Other

The significant components of the $106.1 million increase in *segment profit* of our other operations include the following:

The absence of the previously mentioned $70.4 million Gulf Liquids litigation charge in 2006;

$20 million in higher margins from our olefins production business primarily resulting from the increase in ownership of the Geismar olefins facility in July 2007;

$12 million in higher margins related to the marketing of olefins and $9 million in higher margins related to the marketing of NGLs due to more favorable changes in pricing while product was in transit during 2007 as compared to 2006;

An $8 million reversal of a maintenance accrual (see below);

A $4 million gain in 2007 resulting from deferred consideration received on the sale of an olefins fractionator and the related pipeline system in the Gulf in 2005;

Table of Contents

Management s Discussion and Analysis (Continued)

Partially offset by:

$16 million in higher foreign exchange losses related to the revaluation of current assets held in U.S. dollars within our Canadian operations;

$4 million higher maintenance expenses resulting from the increase in ownership of the Geismar olefins facility;

The absence of a $4 million favorable transportation settlement in 2006.

Effective January 1, 2007, we adopted FASB Staff Position (FSP) No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities.* As a result, we recognized as other income an $8 million reversal of an accrual for major maintenance on our Geismar ethane cracker. We did not apply the FSP retrospectively because the impact to our first quarter 2007 and estimated full year 2007 earnings, as well as the impact to prior periods, is not material. We have adopted the deferral method for accounting for these costs going forward.

Indirect general and administrative expense

The $11.7 million increase in indirect general and administrative expense is due primarily to higher employee, legal, and consulting expenses.

**Gas Marketing Services**

Gas Marketing Services (Gas Marketing) primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production and procuring fuel and shrink gas for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, which were part of our former Power segment, including certain legacy natural gas contracts and positions.

***Overview of Nine Months Ended September 30, 2007***

Gas Marketing s operating results for the first nine months of 2007 reflect unrealized mark-to-market losses primarily caused by a decrease in forward natural gas basis prices against a net long legacy derivative position. Most of these derivative positions are economic hedges but are not designated as hedges for accounting purposes or do not qualify for hedge accounting.

***Outlook for the Remainder of 2007***

For the remainder of 2007, Gas Marketing intends to focus on providing services that support our natural gas businesses. Certain legacy natural gas contracts and positions from our former Power segment are included in the Gas Marketing segment. We intend to liquidate a substantial portion of these legacy contracts. Liquidation of certain of these legacy natural gas contracts could result in losses that may be material in the period in which a sale occurs, but management believes any such losses will not have a materially adverse effect upon our future financial position.

Until such legacy positions are liquidated, Gas Marketing s earnings may continue to reflect mark-to-market volatility from commodity-based derivatives that represent economic hedges but are not designated as hedges for accounting purposes or do not qualify for hedge accounting.

***Period-Over-Period Results***

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| | **(Millions)** | | **(Millions)** | |
| Realized revenues | $ 1,300.7 | $ 1,372.8 | $ 4,084.2 | $ 3,974.6 |
| Net forward unrealized mark-to-market losses | (53.8) | (52.2) | (155.6) | (113.3) |
| Segment revenues | 1,246.9 | 1,320.6 | 3,928.6 | 3,861.3 |
| Costs and operating expenses | 1,311.9 | 1,392.3 | 4,080.3 | 4,042.5 |
| Gross margin | (65.0) | (71.7) | (151.7) | (181.2) |

| | | | | |
|---|---|---|---|---|
| Selling, general and administrative (income) expense | 1.8 | 3.6 | 8.4 | (15.9) |
| Other (income) expense net | | .4 | | (.3) |
| Segment loss | $ (66.8) | $ (75.7) | $ (160.1) | $ (165.0) |

**Table of Contents**

Management s Discussion and Analysis (Continued)

*Three months ended September 30, 2007 vs. three months ended September 30, 2006*

*Realized revenues* represent (1) revenue from the sale of natural gas or completion of energy-related services and (2) gains and losses from the net financial settlement of derivative contracts. *Realized revenues* decreased $72.1 million primarily due to a 12 percent decrease in average prices on physical natural gas sales.

*Net forward unrealized mark-to-market losses* represent changes in the fair values of certain derivative contracts with a future settlement or delivery date that are not designated as hedges for accounting purposes or do not qualify for hedge accounting. *Net forward unrealized mark-to-market losses* for third-quarter 2007 and third-quarter 2006 are comparable. The effect of a decrease in both periods in forward natural gas prices on legacy net forward gas purchase contracts primarily caused *net forward unrealized mark-to-market losses* in both years.

The $80.4 million decrease in Gas Marketing s *costs and operating expenses* is primarily due to a 13 percent decrease in average prices on physical natural gas purchases. Partially offsetting the decrease is a larger adjustment to lower-of-cost-or-market on natural gas inventory held in storage of $21 million in third-quarter 2007 compared to $13 million in third-quarter 2006.

An improvement in accrual gross margin (defined as *realized revenues* less c*osts and operating expenses*) primarily caused the $8.9 million decrease in *segment loss.*

*Nine months ended September 30, 2007 vs. nine months ended September 30, 2006*

The $109.6 million increase in *realized revenues* is primarily due to an 11 percent increase in natural gas sales volumes partially offset by a 7 percent decrease in average prices on physical natural gas sales.

The effect of a change in forward prices on legacy natural gas derivative contracts not designated as hedges for accounting purposes or not qualifying for hedge accounting primarily caused the $42.3 million unfavorable change in *net forward unrealized mark-to-market losses.* A decrease in forward natural gas prices caused greater losses on legacy gas purchase contracts in 2007 than in 2006.

The $37.8 million increase in Gas Marketing s *costs and operating expenses* is primarily due to a 4 percent increase in natural gas purchase volumes. An increased lower-of-cost-or-market adjustment on natural gas inventory held in storage of $25 million in 2007 compared to $20 million in 2006 also contributed to the increase. Partially offsetting the increase is an 8 percent decrease in average prices on physical natural gas purchases.

The unfavorable change in *SG&A (income) expense* is due primarily to the absence of a $24.8 million gain from the sale of certain receivables to a third party in 2006.

An improvement in accrual gross margin, partially offset by the effect of a change in forward prices on legacy natural gas derivative contracts and the unfavorable change in *SG&A (income) expense*, primarily caused the $4.9 million decrease in *segment loss.*

**Other**

***Period-Over-Period Results***

| | **Three months ended September 30,** | | **Nine months ended September 30,** | |
|---|---|---|---|---|
| | **2007** | **2006** | **2007** | **2006** |
| | **(Millions)** | | **(Millions)** | |
| Segment revenues | $ 6.5 | $ 6.4 | $ 19.8 | $ 19.8 |
| Segment profit (loss) | $ .4 | $ (3.4) | $ .3 | $ (10.2) |

The results of our Other segment are relatively comparable to the prior year.

Table of Contents

Management s Discussion and Analysis (Continued)

**Energy Trading Activities**

***Fair Value of Trading and Nontrading Derivatives***

The chart below reflects the fair value of derivatives held for trading purposes as of September 30, 2007. We have presented the fair value of assets and liabilities by the period in which they would be realized under their contractual terms and not as a result of a sale. We have reported the fair value of a portion of these derivatives in assets and liabilities of discontinued operations. (See Note 3 to Consolidated Financial Statements.)

**Net Assets (Liabilities) Trading**
**(Millions)**

| To be Realized in 1-12 Months (Year 1) | To be Realized in 13-36 Months (Years 2-3) | To be Realized in 37-60 Months (Years 4-5) | To be Realized in 61-120 Months (Years 6-10) | To be Realized in 121+ Months (Years 11+) | Net Fair Value |
|---|---|---|---|---|---|
| $(10) | $(7) | $(2) | $(1) | $ | $(20) |

As the table above illustrates, we are not materially engaged in trading activities. However, we hold a substantial portfolio of nontrading derivative contracts. Nontrading derivative contracts are those that hedge or could possibly hedge forecasted transactions on an economic basis. We have designated certain of these contracts as cash flow hedges of Exploration & Production s forecasted sales of natural gas production and Midstream s forecasted sales of natural gas liquids under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133). Of the total fair value of nontrading derivatives, SFAS 133 cash flow hedges had a net liability value of $195 million as of September 30, 2007. In second-quarter 2007, we announced our plans to sell substantially all of our power business. As a result, we determined that it was not probable that the forecasted purchases and sales related to the long-term structured contracts and owned generation associated with our power business would occur. Therefore, in the second quarter of 2007, we discontinued cash flow hedge accounting for the derivative contracts designated as cash flow hedges of those transactions. (See Note 13 of Notes to Consolidated Financial Statements.) The chart below reflects the fair value of derivatives held for nontrading purposes as of September 30, 2007, for Gas Marketing Services, Exploration & Production, Midstream, and nontrading derivatives reported in assets and liabilities of discontinued operations.

**Net Assets (Liabilities) Nontrading**
**(Millions)**

| To be Realized in 1-12 Months (Year 1) | To be Realized in 13-36 Months (Years 2-3) | To be Realized in 37-60 Months (Years 4-5) | To be Realized in 61-120 Months (Years 6-10) | To be Realized in 121+ Months (Years 11+) | Net Fair Value |
|---|---|---|---|---|---|
| $136 | $148 | $ 35 | $ 25 | $ | $344 |

***Counterparty Credit Considerations***

We include an assessment of the risk of counterparty nonperformance in our estimate of fair value for all contracts. Such assessment considers (1) the credit rating of each counterparty as represented by public rating agencies such as Standard & Poor s and Moody s Investors Service, (2) the inherent default probabilities within these ratings, (3) the regulatory environment that the contract is subject to and (4) the terms of each individual contract.

Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We continually assess this risk. We have credit protection within various agreements to call on additional collateral support if necessary. At September 30, 2007, we held collateral support, including letters of credit, of $630 million.

Table of Contents

Management s Discussion and Analysis (Continued)

The gross credit exposure from our derivative contracts, a portion of which is included in assets of discontinued operations (see Note 3 of Notes to Consolidated Financial Statements), as of September 30, 2007, is summarized below.

| **Counterparty Type** | **Investment Grade (a)** | **Total** |
|---|---|---|
| | **(Millions)** | |
| Gas and electric utilities | $ 260.6 | $ 263.8 |
| Energy marketers and traders | 321.3 | 1,622.0 |
| Financial institutions | 2,170.3 | 2,170.3 |
| Other | .3 | 8.0 |
| | $ 2,752.5 | 4,064.1 |
| Credit reserves | | (6.9) |
| Gross credit exposure from derivatives | | $ 4,057.2 |

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of September 30, 2007, is summarized below.

| **Counterparty Type** | **Investment Grade (a)** | **Total** |
|---|---|---|
| | **(Millions)** | |
| Gas and electric utilities | $ 100.8 | $ 101.4 |
| Energy marketers and traders | 22.4 | 214.0 |
| Financial institutions | 279.7 | 279.7 |
| Other | .3 | .4 |
| | $ 403.2 | 595.5 |
| Credit reserves | | (6.9) |
| Net credit exposure from derivatives | | $ 588.6 |

(a) We determine investment grade primarily using publicly available credit ratings. We included counterparties with a minimum

Standard & Poor s rating of BBB- or Moody s Investors Service rating of Baa3 in investment grade. We also classify counterparties that have provided sufficient collateral, such as cash, standby letters of credit, adequate parent company guarantees, and property interests, as investment grade.

Management s Discussion and Analysis (Continued)

**Management s Discussion and Analysis of Financial Condition**

***Outlook***

We believe we have, or have access to, the financial resources and liquidity necessary to meet future requirements for working capital, capital and investment expenditures and debt payments while maintaining a sufficient level of liquidity to reasonably protect against unforeseen circumstances requiring the use of funds. For the remainder of 2007, we expect to maintain liquidity from cash and cash equivalents and unused revolving credit facilities of at least $1 billion. We maintain adequate liquidity to manage margin requirements related to significant movements in commodity prices, unplanned capital spending needs, near term scheduled debt payments, and litigation and other settlements. We expect to fund capital and investment expenditures, debt payments, dividends, stock repurchases, and working capital requirements through cash flow from operations, which is currently estimated to be between $2.1 billion and $2.3 billion in 2007, proceeds from debt issuances and sales of units of Williams Partners L.P., as well as cash and cash equivalents on hand as needed.

We entered 2007 positioned for growth through disciplined investments in our natural gas business. Examples of this planned growth include:

- Exploration & Production will continue its development drilling program in its key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth.

- Gas Pipeline will continue to expand its system to meet the demand of growth markets.

- Midstream will continue to pursue significant deepwater production commitments and expand capacity in the western United States.

We estimate capital and investment expenditures will total approximately $2.8 billion to $3.0 billion in 2007, with approximately $700 million to $900 million to be incurred over the remainder of the year. As a result of increasing our development drilling program, $1.5 billion to $1.6 billion of the total estimated 2007 capital expenditures is related to Exploration & Production. Also within the total estimated expenditures for 2007 is approximately $275 million to $300 million for compliance and maintenance-related projects at Gas Pipeline, including Clean Air Act compliance.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

- Lower than expected levels of cash flow from operations due to commodity pricing volatility. To mitigate this exposure, Exploration & Production has economically hedged the price of natural gas for approximately 171 MMcf per day of its remaining expected 2007 production. In addition, Exploration & Production has collar agreements for each month of 2007 which hedge approximately 273 MMcf per day of remaining expected 2007 production. Also, our former power business has entered into various sales contracts that economically cover substantially all of its fixed demand obligations through 2010. These sales contracts and related fixed demand obligations are included in the anticipated sale of substantially all of our power business.

- Sensitivity of margin requirements associated with our marginable commodity contracts. As of September 30, 2007, we estimate our exposure to additional margin requirements through the remainder of 2007 to be no more than $478 million, using a statistical analysis at a 99 percent confidence level. This exposure includes contracts related to discontinued operations.

- Exposure associated with our efforts to resolve regulatory and litigation issues. (See Note 12 of Notes to Consolidated Financial Statements.)

***Overview***

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees.

**Table of Contents**

Management s Discussion and Analysis (Continued)

Under the credit agreement, Exploration & Production is not required to post collateral as long as the value of its domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. Exploration & Production is subject to additional covenants under the credit agreement including restrictions on hedge limits, the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments, such as dividends, under certain circumstances.

On April 4, 2007, Northwest Pipeline retired $175 million of 8.125 percent senior notes due 2010. Northwest Pipeline paid premiums of approximately $7.1 million in conjunction with the early debt retirement.

On April 5, 2007, Northwest Pipeline issued $185 million aggregate principal amount of 5.95 percent senior unsecured notes due 2017 to certain institutional investors in a private debt placement. Northwest Pipeline initiated an exchange offer on July 26, 2007, which expired on August 23, 2007. Northwest Pipeline received full participation in the exchange offer. (See Note 10 of Notes to Consolidated Financial Statements.)

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. We intend to purchase shares of our stock from time to time in open market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors. This stock-repurchase program does not have an expiration date. We plan to fund this program with cash on hand. In third-quarter 2007, we purchased approximately 7.45 million shares for $234 million under the program at an average cost of $31.40 per share.

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to become a publicly traded master limited partnership that will own and operate natural gas transportation and storage assets. On September 12, 2007, WMZ filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of 13 million common units, representing limited partner interests, plus an option for the underwriters to purchase up to an additional 1.95 million common units. On October 29, 2007, Williams Pipeline Partners L.P. filed an amendment to the registration statement. A subsidiary of ours will serve as the general partner of WMZ.

*Credit ratings*

On March 19, 2007, Standard & Poor s raised our senior unsecured debt rating from a BB to a BB with a stable ratings outlook. On May 21, 2007, Standard & Poor s revised its ratings outlook to positive from stable. With respect to Standard & Poor s, a rating of BBB or above indicates an investment grade rating. A rating below BBB indicates that the security has significant speculative characteristics. A BB rating indicates that Standard & Poor s believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor s may modify its ratings with a + or a sign to show the obligor s relative standing within a major rating category.

Moody s Investors Service rates our senior unsecured debt at a Ba2 and on May 21, 2007, placed this rating on review for possible upgrade. With respect to Moody s, a rating of Baa or above indicates an investment grade rating. A rating below Baa is considered to have speculative elements. A Ba rating indicates an obligation that is judged to have speculative elements and is subject to substantial credit risk. The 1 , 2 and 3 modifiers show the relative standing within a major category. A 1 indicates that an obligation ranks in the higher end of the broad rating category, 2 indicates a mid-range ranking, and 3 ranking at the lower end of the category.

Fitch Ratings rates our senior unsecured debt at a BB+ and revised its ratings outlook to positive from stable on May 21, 2007. With respect to Fitch, a rating of BBB or above indicates an investment grade rating. A rating below BBB is considered speculative grade. A BB rating from Fitch indicates that there is a possibility of credit risk developing, particularly as the result of adverse economic change over time; however, business or financial alternatives may be available to allow financial commitments to be met. Fitch may add a + or a sign to show the obligor s relative standing within a major rating category.

Management s Discussion and Analysis (Continued)

*Liquidity*

Our internal and external sources of liquidity include cash generated from our operations, bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. While most of our sources are available to us at the parent level, others are available to certain of our subsidiaries, including equity and debt issuances from Williams Partners L.P. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

**Available Liquidity**

| | | September 30, 2007 (Millions) |
|---|---|---|
| Cash and cash equivalents* | $ | 1,455.4 |
| Auction rate securities and other liquid securities | | 43.8 |
| Available capacity under our four unsecured revolving and letter of credit facilities totaling $1.2 billion | | 432.2 |
| Available capacity under our $1.5 billion unsecured revolving and letter of credit facility** | | 1,472.0 |
| | $ | 3,403.4 |

* *Cash and cash equivalents* includes $205.5 million of funds received from third parties as collateral. The obligation for these amounts is reported as *customer margin deposits payable* on the Consolidated Balance Sheet. Also included is $465 million of cash and cash equivalents that is being utilized by certain subsidiary and international operations.

** This facility is guaranteed by

Williams Gas Pipeline Company, L.L.C. Northwest Pipeline and Transco each have access to $400 million under this facility to the extent not utilized by us. Williams Partners L.P. has access to $75 million, to the extent not utilized by us, that we guarantee.

In addition to the above, Northwest Pipeline and Transco have shelf registration statements available for the issuance of up to $350 million aggregate principal amount of debt securities. If the credit rating of Northwest Pipeline or Transco is below investment grade for all credit rating agencies, they can only use their shelf registration statements to issue debt if such debt is guaranteed by us.

Williams Partners L.P. has a shelf registration statement available for the issuance of approximately $1.2 billion aggregate principal amount of debt and limited partnership unit securities.

In addition, at the parent-company level, we have a shelf registration statement that allows us to issue publicly registered debt and equity securities as needed.

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks which serves to reduce our usage of cash and other credit facilities for margin requirements related to our hedging activities as well as lower transaction fees. (See Note 10 of Notes to Consolidated Financial Statements.)

On May 9, 2007, we amended our $1.5 billion unsecured credit facility extending the maturity date from May 1, 2009 to May 1, 2012. Applicable borrowing rates and commitment fees for investment grade credit ratings were also modified.

***Sources (Uses) of Cash***

| | Nine months ended September 30, 2007 | Nine months ended September 30, 2006 |
|---|---|---|
| Net cash provided (used) by: | | |
| Operating activities | $ 1,677.8 | $ 1,314.3 |
| Financing activities | (508.2) | (73.3) |
| Investing activities | (1,982.8) | (1,763.6) |
| Decrease in cash and cash equivalents | $ (813.2) | $ (522.6) |

**Table of Contents**

Management s Discussion and Analysis (Continued)

*Operating activities*

Our *net cash provided by operating activities* for the nine months ended September 30, 2007 increased $363.5 million from the same period in 2006. The primary driver of this increase is an increase in our operating results.

*Financing activities*

During the first quarter of 2006, we paid $25.8 million in premiums for early debt retirement costs.

See Overview for a discussion of 2007 debt issuances, retirements, and stock repurchases.

Quarterly dividends paid on common stock were $.10 per common share during the third quarter of 2007 and totaled $173.9 million for the nine months ended September 30, 2007. During the third quarter of 2006, quarterly dividends paid on common stock were $.09 per common share and totaled $151.8 million for the nine months ended September 30, 2006. Quarterly dividends paid on common stock increased from $.075 to $.09 per common share during second quarter 2006 and from $.09 to $.10 per common share during second quarter 2007.

*Investing activities*

During the first nine months of 2007, capital expenditures totaled $2.1 billion and were primarily related to Exploration & Production s increased drilling activity, mostly in the Piceance basin.

During the first nine months of 2007, we purchased $304.3 million of auction rate securities and received $352.5 million from the sale of auction rate securities. These are utilized as a component of our overall cash management program.

*Off-balance sheet financing arrangements and guarantees of debt or other commitments*

Our $1.5 billion unsecured revolving and letter of credit facility is guaranteed by Williams Gas Pipeline Company, L.L.C. Northwest Pipeline and Transco each have access to $400 million and Williams Partners L.P. has access to $75 million under the facility to the extent not otherwise utilized by us. We guarantee the obligations of Williams Partners L.P. for up to $75 million.

We have various other guarantees and commitments which are disclosed in Note 12 of Notes to Consolidated Financial Statements. We do not believe these guarantees or the possible fulfillment of them will prevent us from meeting our liquidity needs.

Table of Contents

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

***Interest Rate Risk***

Our interest rate risk exposure is primarily associated with our debt portfolio and has not materially changed during the first nine months of 2007. See Note 10 of Notes to Consolidated Financial Statements.

***Commodity Price Risk***

We are exposed to the impact of fluctuations in the market price of natural gas, electricity and natural gas liquids, as well as other market factors, such as market volatility and commodity price correlations, including correlations between natural gas and power prices. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our proprietary trading activities. We manage the risks associated with these market fluctuations using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to changes in energy-commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted, and changes in interest rates. We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios.

Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolio in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Derivative contracts designated as normal purchases or sales under SFAS 133 and nonderivative energy contracts have been excluded from our estimation of value at risk.

*Trading*

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. A portion of these derivative contracts are included in our assets and liabilities of discontinued operations. Our value at risk for contracts held for trading purposes was approximately $2 million at September 30, 2007, and $1 million at December 31, 2006.

*Nontrading*

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from the following activities:

| Segment | Commodity Price Risk Exposure |
|---|---|
| Exploration & Production | Natural gas sales |
| Midstream | Natural gas purchases<br>NGL sales |
| Gas Marketing Services | Natural gas purchases and sales |

Our assets and liabilities of discontinued operations also include derivative contracts that economically hedge or could potentially hedge the commodity price risk exposure from natural gas purchases and electricity purchases and sales.

The value at risk for derivative contracts held for nontrading purposes was $7 million at September 30, 2007, and $12 million at December 31, 2006. A portion of these derivative contracts are included in our assets and liabilities of discontinued operations. Under our agreement to sell our power business to Bear Energy, LP, for $512 million, this amount will be reduced by expected net portfolio cash flows from an April 1, 2007, valuation date through the transaction closing date. Mark-to-market gains and losses between this valuation date and the close of the transaction will not impact the economic value of the sale, although they may change the recorded gain or loss on the sale as derivative assets and liabilities included in the sale continue to be valued at fair value.

Certain of the other derivative contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS 133. Though these contracts are included in our value-at-risk calculation, any changes in the fair value of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Table of Contents

## Item 4
## Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) (Disclosure Controls) was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our Disclosure Controls or our internal controls over financial reporting (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and Internal Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and the Internal Controls will be modified as systems change and conditions warrant.

### Third-Quarter 2007 Changes in Internal Controls Over Financial Reporting

There have been no changes during third-quarter 2007, that have materially affected, or are reasonably likely to materially affect, our Internal Controls over financial reporting.

Table of Contents

# PART II. OTHER INFORMATION

**Item 1. Legal Proceedings**

The information called for by this item is provided in Note 12 Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.

**Item 1A. Risk Factors**

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006, includes certain risk factors that could materially affect our business, financial condition or future results. Those Risk Factors have not materially changed except as set forth below:

***The outcome of pending rate cases to set the rates we can charge customers on certain of our pipelines might result in rates that do not provide an adequate return on the capital we have invested in those pipelines.***

In 2006 we filed rate cases with the FERC to request changes to the rates we charge on Northwest Pipeline and Transco. Northwest Pipeline has settled its rate case and Transco has an agreement in principle to settle its rate case. Final resolution of the Transco rate case is subject to the filing of a formal stipulation and agreement and subsequent approval by the FERC. Pending a FERC-approved settlement, there is a risk that rates set by the FERC will be lower than is necessary to provide Transco with an adequate return on the capital we have invested in these assets. There is also the risk that higher rates will cause Transco s customers to look for alternative ways to transport their natural gas.

**Item 2. Unregistered Sales of Equity Securities and Use of Proceeds**

**ISSUER PURCHASES OF EQUITY SECURITIES**

| Period | (a) Total Number of Shares Purchased | (b) Average Price Paid Per Share | (c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[1] | (d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| July 1 July 31, 2007 | | | | |
| August 1 August 31, 2007 | 7,198,500 | $ 31.40 | 7,198,500 | $ 773,948,316 |
| September 1 September 30, 2007 | 250,000 | $ 31.23 | 250,000 | $ 766,140,266 |
| **Total** | 7,448,500 | $ 31.40 | 7,448,500 | $ 766,140,266 |

1 We announced a stock repurchase program on July 20, 2007. Our board of directors has authorized the repurchase of up to $1 billion of

the company s common stock. The stock repurchase program has no expiration date. We intend to purchase shares of our stock from time to time in open market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors.

**Item 6. Exhibits**

(a) The exhibits listed below are filed or furnished as part of this report:

Exhibit 4.1 Amendment No. 2 dated October 12, 2007 to the Amended and Restated Rights Agreement dated September 21, 2004 (filed as Exhibit 4.1 to our current report on Form 8-K filed October 15, 2007).

Exhibit 12 Computation of Ratio of Earnings to Fixed Charges.

Exhibit 31.1 Certification of Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

**Table of Contents**

Exhibit 31.2 Certification of Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 32 Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Table of Contents

## SIGNATURE

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

THE WILLIAMS COMPANIES, INC.
(Registrant)

/s/Ted T. Timmermans
Ted T. Timmermans
Controller (Duly Authorized Officer and
Principal Accounting Officer)

November 1, 2007