WILLIAMS COMPANIES INC
Form 10-Q
November 02, 2006

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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, 2006

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 31, 2006
Common Stock, $1 par value	596,338,450 Shares

The Williams Companies, Inc.
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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 and gas prices and demand.

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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 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, 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, 2005.

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

(Dollars in millions, except per-share amounts)	Three months ended September 30, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
Revenues:				
Exploration & Production	$ 371.1	$ 318.4	$ 1,069.4	$ 848.9
Gas Pipeline	334.2	345.8	1,005.5	1,038.1
Midstream Gas & Liquids	1,117.0	754.7	3,139.9	2,341.8
Power	2,104.1	2,242.9	5,764.3	6,307.2
Other	6.4	6.3	19.8	19.4
Intercompany eliminations	(632.8)	(585.8)	(1,956.3)	(1,647.9)
Total revenues	3,300.0	3,082.3	9,042.6	8,907.5
Segment costs and expenses:				
Costs and operating expenses	2,822.4	2,826.2	7,684.9	7,708.1
Selling, general and administrative expenses	128.0	90.6	308.3	226.8
Other (income) expense net	(15.8)	(21.4)	23.6	(1.3)
Total segment costs and expenses	2,934.6	2,895.4	8,016.8	7,933.6
General corporate expenses	35.0	42.8	99.3	106.3
Securities litigation settlement and related costs	3.4		165.3	
Operating income (loss):				
Exploration & Production	138.9	153.0	395.4	367.9
Gas Pipeline	99.3	144.1	339.0	456.7
Midstream Gas & Liquids	204.9	117.9	471.0	343.7
Power	(77.3)	(227.4)	(179.5)	(190.3)
Other	(.4)	(0.7)	(.1)	(4.1)
General corporate expenses	(35.0)	(42.8)	(99.3)	(106.3)
Securities litigation settlement and related costs	(3.4)		(165.3)	
Total operating income	327.0	144.1	761.2	867.6
Interest accrued	(162.7)	(166.0)	(507.0)	(495.3)
Interest capitalized	4.8	1.8	11.8	4.3
Investing income	50.7	31.1	140.9	44.9
Early debt retirement costs			(31.4)	
Minority interest in income of consolidated subsidiaries	(12.1)	(6.8)	(27.5)	(16.8)
Other income (expense) net	2.8	(1.1)	18.9	12.5

Income from continuing operations before income taxes	210.5	3.1	366.9	417.2
Provision (benefit) for income taxes	100.4	(2.6)	189.6	168.6
Income from continuing operations	110.1	5.7	177.3	248.6
Loss from discontinued operations	(3.9)	(1.3)	(15.2)	(1.8)
Net income	$ 106.2	$ 4.4	$ 162.1	$ 246.8
Basic earnings per common share:				
Income from continuing operations	$ .19	$ .01	$ .30	$ .43
Loss from discontinued operations	(.01)		(.03)	
Net income	$ .18	$ .01	$ .27	$ .43
Weighted-average shares (thousands)	596,199	572,543	594,406	569,426
Diluted earnings per common share:				
Income from continuing operations	$ .19	$ .01	$ .29	$ .42
Loss from discontinued operations	(.01)		(.02)	
Net income	$ .18	$ .01	$ .27	$ .42
Weighted-average shares (thousands)	609,062	580,735	608,045	604,749
Cash dividends per common share	$ .09	$ .075	$ .255	$ .175

See accompanying notes.

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

(Dollars in millions, except per-share amounts)	September 30, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,074.6	$ 1,597.2
Restricted cash	79.3	92.9
Accounts and notes receivable (net of allowance of $23.9 in 2006 and $86.6 in 2005)	1,232.9	1,613.8
Inventories	260.2	272.6
Derivative assets	2,311.3	5,299.7
Margin deposits	127.0	349.2
Assets of discontinued operations	5.3	12.8
Deferred income taxes	293.1	241.0
Other current assets and deferred charges	306.3	218.1
Total current assets	5,690.0	9,697.3
Restricted cash	40.9	36.5
Investments	929.5	887.8
Property, plant and equipment net	13,651.8	12,409.2
Derivative assets	2,739.1	4,656.9
Goodwill	1,011.4	1,014.5
Other assets and deferred charges	758.8	740.4
Total assets	$ 24,821.5	$ 29,442.6
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 1,055.0	$ 1,360.6
Accrued liabilities	1,229.5	1,121.9
Customer margin deposits payable	77.4	320.7
Liabilities of discontinued operations	1.3	1.2
Derivative liabilities	2,246.0	5,523.2
Long-term debt due within one year	142.3	122.6
Total current liabilities	4,751.5	8,450.2
Long-term debt	7,275.2	7,590.5
Deferred income taxes	2,897.7	2,508.9
Derivative liabilities	2,377.4	4,331.1
Other liabilities and deferred income	1,010.1	920.3
Contingent liabilities and commitments (Note 11)		
Minority interests in consolidated subsidiaries	438.4	214.1

Stockholders equity:		
Common stock (960 million shares authorized at $1 par value; 601.8 million shares issued at September 30, 2006 and 579.1 million shares issued at December 31, 2005)	601.8	579.1
Capital in excess of par value	6,567.6	6,327.8
Accumulated deficit	(1,125.6)	(1,135.9)
Accumulated other comprehensive income (loss)	68.7	(297.8)
Other	(.1)	(4.5)
	6,112.4	5,468.7
Less treasury stock, at cost (5.7 million shares of common stock in 2006 and 2005)	(41.2)	(41.2)
Total stockholders equity	6,071.2	5,427.5
Total liabilities and stockholders equity	$ 24,821.5	$ 29,442.6

See accompanying notes.

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

(Dollars in millions)	Nine months ended September 30, 2006	2005
OPERATING ACTIVITIES:		
Net income	$ 162.1	$ 246.8
Adjustments to reconcile to net cash provided by operations:		
Loss from discontinued operations	15.2	1.8
Depreciation, depletion and amortization	627.9	545.9
Accrual for securities litigation settlement and related costs	165.3	
Provision (benefit) for deferred income taxes	129.0	(63.1)
Provision for loss on investments, property and other assets	6.2	56.3
Net gain on disposition of assets	(13.6)	(47.0)
Early debt retirement costs	31.4	
Minority interest in income of consolidated subsidiaries	27.5	16.8
Amortization of stock-based awards	32.5	9.9
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	359.1	(115.0)
Inventories	12.5	(39.9)
Margin deposits and customer margin deposits payable	(21.1)	61.0
Other current assets and deferred charges	(47.1)	(2.2)
Accounts payable	(297.9)	114.5
Accrued liabilities	(185.9)	52.7
Changes in current and noncurrent derivative assets and liabilities	252.1	203.1
Other, including changes in noncurrent assets and liabilities	52.5	40.7
Net cash provided by operating activities of continuing operations	1,307.7	1,082.3
Net cash provided by operating activities of discontinued operations	6.6	
Net cash provided by operating activities	1,314.3	1,082.3
FINANCING ACTIVITIES:		
Proceeds from long-term debt	699.4	
Payments of long-term debt	(773.6)	(243.6)
Proceeds from issuance of common stock	21.6	303.4
Proceeds from sale of limited partner units of consolidated partnership	225.2	111.0
Payments for debt issuance costs and amendment fees	(26.9)	(29.6)
Premiums paid on early debt retirement	(25.8)	
Dividends paid	(151.8)	(100.0)
Dividends and distributions paid to minority interests	(28.1)	(19.8)
Changes in restricted cash	5.0	37.1
Changes in cash overdrafts	(17.0)	58.7
Other net	(1.3)	.1
Net cash provided (used) by financing activities	(73.3)	117.3

INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(1,758.9)	(885.9)
Net proceeds from dispositions	(10.6)	39.0
Proceeds from contract termination payment	3.3	87.9
Changes in accounts payable and accrued liabilities	37.8	(4.0)
Purchases of investments/advances to affiliates	(45.6)	(98.2)
Purchases of auction rate securities	(375.8)	(171.3)
Proceeds from sales of auction rate securities	319.8	115.2
Proceeds from sales of businesses		31.4
Proceeds received on sale of note from WilTel		54.7
Proceeds from dispositions of investments and other assets	51.3	51.6
Other net	15.1	10.5
Net cash used by investing activities	(1,763.6)	(769.1)
Increase (decrease) in cash and cash equivalents	(522.6)	430.5
Cash and cash equivalents at beginning of period	1,597.2	930.0
Cash and cash equivalents at end of period	$ 1,074.6	$ 1,360.5

See accompanying notes.

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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 our Annual Report on Form 10-K. 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, 2006, and results of operations for the three and nine months ended September 30, 2006 and 2005 and cash flows for the nine months ended September 30, 2006 and 2005.

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

Amounts presented as discontinued operations in our financial statements relate to residual activity and/or adjustments from businesses that were sold or otherwise disposed of in prior years. The most recent such sale closed in July 2004.

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

Certain amounts have been reclassified to conform to current classifications.

In February 2005, we formed Williams Partners L.P., a limited partnership engaged in the business of gathering, transporting and processing natural gas and fractionating and storing natural gas liquids. In August 2005, we completed our initial public offering of five million common units of Williams Partners L.P. We currently own approximately 39 percent of Williams Partners L.P., including the interests of the general partner, which is wholly-owned by us. Considering the presumption of control of the general partner 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, Williams Partners L.P. is consolidated within our Midstream Gas & Liquids (Midstream) segment.

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Notes (Continued)

Note 3. Asset Sales, Impairments and Other Accruals

Significant gains or losses from asset sales, impairments and other accruals or adjustments reflected in our Consolidated Statement of Income are included in the following table:

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(Millions)		(Millions)	
Costs and operating expenses:				
Gas Pipeline				
Liability reversal associated with a favorable rate case ruling involving adjustments to estimated gas purchase costs for operations in prior periods	$	$(14.2)	$	$(14.2)
Adjustments to correct the carrying value of certain liabilities recorded in prior periods				(12.1)
Midstream				
Adjustment of accounts payable accrual (excluding $.8 million recorded in *SG&A*)	9.8		9.8	
Selling, general and administrative expenses (SG&A):				
Gas Pipeline				
Adjustments to correct the carrying value of certain liabilities recorded in prior periods				(5.6)
Reduction in pension expense for the cumulative impact of correcting an error attributable to 2003 and 2004				(17.1)
Other (income) expense net (within segment costs and expenses):				
Exploration & Production				
Gains on sales of certain natural gas properties		(21.7)		(29.6)
Midstream				
Gains on sales of properties	(7.9)		(7.9)	
Losses on asset retirements, primarily due to the impact of accelerating the timing of abandonment	5.2		5.2	
Accrual for Gulf Liquids litigation contingency. Associated with this contingency is an interest expense accrual of $0.6 million for the third quarter and $20.6 million year-to-date, which is included in *interest accrued* (see Note 11)	2.4		70.4	

Settlement of an international contract dispute			(9.0)	
Gas Pipeline				
Reversal of an accrued litigation contingency due to a favorable court ruling. Associated with this contingency reversal is $5 million of income due to reversing accrued interest, which is included in *interest accrued*			(2.0)	
Power				
Accrual for litigation contingencies	3.5	0.4	3.5	13.5
Reduction of contingent obligations associated with our former distributive power generation business	(12.7)		(12.7)	
General corporate expenses				
Other				
Insurance settlement charges associated with certain insurance coverage allocation issues		13.8		13.8
Investing income (loss):				
Midstream				
Gain on sale of remaining interests in Mid-America Pipeline (MAPL) and Seminole Pipeline (Seminole)				8.6
Other				
Impairment of investment in Longhorn Partners Pipeline L.P. (Longhorn)				(49.1)
Loss from discontinued operations:				
$19.2 million accrual for an adverse arbitration award related to our former chemical fertilizer business, net of taxes of $7.3 million (see Note 11)			(11.9)	
$6 million claim settlement related to a former exploration business, net of taxes of $2.3 million	(3.7)		(3.7)	

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Notes (Continued)

Note 4. Provision (Benefit) for Income Taxes

The *provision (benefit) for income taxes* includes:

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(Millions)		(Millions)	
Current:				
Federal	$ 5.2	$ 205.6	$ 17.9	$ 212.9
State	(.8)	(1.3)	10.9	6.7
Foreign	14.6	5.8	31.8	12.1
	19.0	210.1	60.6	231.7
Deferred:				
Federal	52.3	(212.6)	85.0	(73.5)
State	21.5	(1.3)	25.7	14.8
Foreign	7.6	1.2	18.3	(4.4)
	81.4	(212.7)	129.0	(63.1)
Total provision (benefit)	$ 100.4	$ (2.6)	$ 189.6	$ 168.6

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.

The effective income tax rate benefit for the three months ended September 30, 2005, is less than the federal statutory rate due primarily to the effect of income tax settlements (including a reduction of an accrual for income tax contingencies) and taxes on foreign operations, partially offset by state income taxes and an increase in valuation allowance. The significant current federal provision and deferred federal benefit are primarily the result of income tax settlements in the third quarter.

The effective income tax rate for the nine months ended September 30, 2005, is greater than the federal statutory rate due primarily to the effect of state income taxes, an increase in valuation allowance and nondeductible expenses, partially offset by income tax settlements (including a reduction of an accrual for income tax contingencies) and taxes on foreign operations.

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Notes (Continued)

Note 5. Earnings Per Common Share from Continuing Operations

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

	Three months ended September 30, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
	(Dollars in millions, except per-share amounts; shares in thousands)		(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)	$ 110.1	$ 5.7	$ 177.3	$ 248.6
Basic weighted-average shares (2)	596,199	572,543	594,406	569,426
Effect of dilutive securities:				
Unvested deferred shares (3)	1,032	2,999	921	2,849
Stock options	4,503	5,193	4,351	4,926
Convertible debentures	7,328		8,367	27,548
Diluted weighted-average shares	609,062	580,735	608,045	604,749
Earnings per share from continuing operations:				
Basic	$ .19	$ .01	$ .30	$ .43
Diluted	$ .19	$ .01	$ .29	$ .42

(1) The three and nine months ended September 30, 2006 and the nine months ended September 30, 2005, include $.7 million, $2.3 million, and $7.6 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) During January 2006, we issued 20.2 million shares of common stock related to a conversion offer for our 5.5 percent convertible debentures (see Note 10).

(3) The unvested deferred shares outstanding at September 30, 2006, will vest over a period from November 2006 through September 2009.

Approximately 27.5 million weighted-average shares related to the assumed conversion of convertible debentures, as well as the related interest, net of tax, have been excluded from the computation of diluted earnings per common share for the three months ended September 30, 2005. Inclusion of these shares would have an antidilutive effect on diluted earnings per common share. If no other components used to calculate diluted earnings per common share change, we estimate the assumed conversion of convertible debentures would have become dilutive and therefore be included in diluted earnings per common share at an income from continuing operations available to common stockholders amount of $53.7 million for the three months ended September 30, 2005.

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, 2006	**September 30, 2005**
Options excluded (millions)	4.2	4.8
Weighted-average exercise prices of options excluded	$ 35.33	$ 35.23
Exercise price ranges of options excluded	$23.88-$42.29	$23.88-$42.29
Third quarter weighted-average market price	$ 23.87	$ 21.75

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Notes (Continued)

Note 6. Employee Benefit Plans

Net periodic pension expense (income) and *other postretirement benefit expense* for the three and nine months ended September 30, 2006 and 2005 are as follows:

	Pension Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(Millions)		(Millions)	
Components of net periodic pension expense (income):				
Service cost	$ 5.5	$ 5.4	$ 16.6	$ 16.2
Interest cost	12.7	12.0	37.6	35.8
Expected return on plan assets	(16.7)	(17.8)	(50.1)	(53.3)
Amortization of prior service credit	(.1)	(.1)	(.4)	(.3)
Recognized net actuarial (gain) loss	5.2	1.7	14.7	(8.3)
Regulatory asset amortization (deferral)		.7	(.1)	.3
Settlement/curtailment expense		.1		2.7
Net periodic pension expense (income)	$ 6.6	$ 2.0	$ 18.3	$ (6.9)

	Other Postretirement Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(Millions)		(Millions)	
Components of net periodic other postretirement benefit expense:				
Service cost	$ .8	$ .8	$ 2.4	$ 2.3
Interest cost	4.4	5.8	13.0	14.6
Expected return on plan assets	(2.7)	(2.9)	(8.3)	(8.6)
Amortization of prior service credit	(.1)	(.1)	(.3)	(4.2)
Recognized net actuarial loss		.9		2.4
Regulatory asset amortization	1.8	1.5	5.4	5.3
Net periodic other postretirement benefit expense	$ 4.2	$ 6.0	$ 12.2	$ 11.8

Net periodic pension expense (income) for the nine months ended September 30, 2005, includes a $17.1 million reduction to expense to record the cumulative impact of a correction of an error determined to have occurred in 2003 and 2004. The error was associated with our third-party actuarial computation of annual *net periodic pension expense* which resulted from the identification of errors in certain Transcontinental Gas Pipe Line Corporation (Transco) participant data involving annuity contract information utilized for 2003 and 2004. The adjustment is reflected as $16.1 million within *recognized net actuarial (gain) loss* and $1 million within *regulatory asset amortization (deferral)*.

Through September 30, 2006, we have contributed $3.2 million to our pension plans and $11.0 million to our other postretirement benefit plans. We presently anticipate making additional contributions of approximately $14 million to our pension plans in 2006 for a total of approximately $17 million. We presently anticipate making additional contributions of approximately $4 million to our other postretirement benefit plans in 2006 for a total of approximately $15 million.

Note 7. Stock-Based Compensation

Plan Information

The Williams Companies, Inc. 2002 Incentive Plan (the Plan) was approved by stockholders on May 16, 2002, and amended and restated on May 15, 2003, and January 23, 2004. The Plan provides for common-stock-based awards to both employees and nonmanagement directors. Upon approval by the stockholders, all prior stock plans were terminated resulting in no further grants being made from those plans. However, awards outstanding in those prior plans remain in those plans with their respective terms and provisions.

The Plan permits the granting of various types of awards including, but not limited to, stock options and deferred stock. Awards may be granted for no consideration other than prior and future services or based on certain financial performance targets being achieved. At September 30, 2006, 42.8 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 19.9 million shares were available for future grants. At December 31, 2005, 45 million shares of our common stock were reserved for issuance, of which 21.6 million were available for future grants.

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Notes (Continued)

Accounting for Stock-Based Compensation

Prior to January 1, 2006, we accounted for the Plan under the recognition and measurement provisions of Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations, as permitted by Financial Accounting Standards Board (FASB) Statement No. 123, Accounting for Stock-Based Compensation (SFAS No. 123). Compensation cost for stock options was not recognized in the Consolidated Statement of Income for the nine months ending September 30, 2005, as all options granted under the Plan had an exercise price equal to the market value of the underlying common stock on the date of the grant. Prior to January 1, 2006, compensation cost was recognized for deferred share awards. Effective January 1, 2006, we adopted the fair value recognition provisions of FASB Statement No. 123(R), Share-Based Payment (SFAS No. 123(R)), using the modified-prospective method. Under this method, compensation cost recognized in the first nine months of 2006 includes: (1) compensation cost for all share-based payments granted through December 31, 2005, but for which the requisite service period had not been completed as of December 31, 2005, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123, and (2) compensation cost for most share-based payments granted subsequent to December 31, 2005, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123(R). The performance targets for certain performance based deferred shares have not been established and therefore expense is not currently recognized. Results for prior periods have not been restated.

Total stock-based compensation expense for the three and nine months ending September 30, 2006, was $11.1 million and $32.5 million, respectively. The year-to-date amount reflects a reduction of $.3 million of previously recognized compensation cost for deferred share awards related to the estimated number of awards expected to be forfeited. This adjustment is not considered material for reporting as a cumulative effect of a change in accounting principle. Measured but unrecognized stock-based compensation expense at September 30, 2006, was approximately $61 million, which does not include the effect of estimated forfeitures of $2.2 million. This amount is comprised of approximately $17 million related to stock options and approximately $44 million related to deferred shares. These amounts are expected to be recognized over a weighted-average period of 1.8 years.

As a result of adopting SFAS No. 123(R), our *income from continuing operations before income taxes* and *net income* for the three months ending September 30, 2006, are approximately $3.9 million and $2.3 million lower, respectively, and for the nine months ending September 30, 2006, are approximately $14.5 million and $8.9 million lower, respectively, than if we continued to account for share-based compensation under APB No. 25. For the nine months ending September 30, 2006, basic and diluted earnings per share are $.02 and $.01 lower, respectively, due to the implementation of SFAS No. 123(R).

The following table illustrates the effect on *net income* and *earnings per common share* if we had applied the fair value recognition provisions to SFAS No. 123 to options granted under the Plan for the three and nine months ending September 30, 2005. For purposes of this pro forma disclosure, the value of the options was estimated using a Black-Scholes option pricing model and amortized to expense over the vesting period of the options.

	Three months ended September 30, 2005 (Dollars in millions, except per share amounts)	Nine months ended September 30, 2005 (Dollars in millions, except per share amounts)
Net income, as reported	$ 4.4	$ 246.8
Add: Stock-based employee compensation expense included in the Consolidated Statement of Income, net of related tax effects	2.8	6.8
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(4.8)	(12.8)

Pro forma net income	$	2.4	$	240.8
Earnings per share:				
Basic-as reported	$	.01	$	.43
Basic-pro forma	$		$	.42
Diluted-as reported	$	.01	$	.42
Diluted-pro forma	$		$	.41

Stock Options

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. Stock options generally become exercisable over a three-year period from the date of grant and generally expire ten years after the grant.

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Notes (Continued)

The following summary reflects stock option activity and related information for the nine-month period ending September 30, 2006.

Stock Options	Options (Millions)	Weighted-Average Exercise Price	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2005	20.4	$ 16.63	
Granted	1.2	$ 21.64	
Exercised	(1.9)	$ 11.40	$ 22.7
Cancelled	(.7)	$ 30.11	
Outstanding at September 30, 2006	19.0	$ 17.01	$ 178.7
Exercisable at September 30, 2006	14.5	$ 16.97	$ 148.1

The following summary provides additional information about stock options that are outstanding and exercisable at September 30, 2006.

	Stock Options Outstanding			Stock Options Exercisable		
Range of Exercise Prices	Options (Millions)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Options (Millions)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)
$2.27 to $10.00	9.0	$ 7.08	6.0	7.7	$ 6.59	5.8
$10.38 to $16.40	1.0	$ 15.50	4.0	1.0	$ 15.55	4.0
$17.10 to $31.58	5.7	$ 21.29	6.9	2.5	$ 22.79	4.6
$33.51 to $42.28	3.3	$ 37.62	1.8	3.3	$ 37.62	1.8
Total	19.0	$ 17.01	5.5	14.5	$ 16.97	4.6

The estimated weighted-average grant-date fair value of stock options granted during the first nine months of 2006 is $8.35 per share. We used the Black-Scholes option pricing model to estimate the grant-date fair value of each stock option granted. The fair values of options granted during the first nine months of 2006 were estimated using the following assumptions:

Expected dividend yield	1.42%
Expected volatility	36.30%
Risk-free interest rate	4.66%
Expected life (years)	6.5

The expected dividend yield is based on the average annual dividend yield as of the grant date. Expected volatility is based on the historical volatility of our stock and the implied volatility of our stock based on traded options. In calculating historical volatility, returns during calendar year 2002 were excluded as the extreme volatility during that time is not reasonably expected to be repeated in the future. The risk-free interest rate is based on the U.S. Treasury

Constant Maturity rates as of the grant date. The expected life of the option is based on historical exercise behavior and expected future experience.

Cash received from stock option exercises was $21.6 million during the first nine months of 2006.

Nonvested Deferred Shares

Deferred shares are generally valued at market value on the grant date of the award and generally vest over three years. Deferred share expense, net of estimated forfeitures, is generally recognized over the vesting period on a straight-line basis.

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Notes (Continued)

The following summary reflects nonvested deferred share activity and related information for the nine-month period ended September 30, 2006.

Deferred Shares	Shares (Millions)	Weighted-Average Fair Value*
Nonvested at December 31, 2005	2.8	$ 14.60
Granted	1.4	$ 21.85
Forfeited	(.1)	$ 17.96
Vested	(.6)	$ 11.59
Nonvested at September 30, 2006	3.5	$ 18.40

* Performance-based shares are valued at the end-of-period market price. All other shares are valued at the grant-date market price.

The total market value of shares vested and issued during the first nine months of 2006 was approximately $11.5 million.

Performance-based share awards issued under the Plan represent 35 percent of nonvested deferred shares outstanding at September 30, 2006. These awards are generally earned at the end of a three-year period based on actual performance against a performance target. Based on the extent to which certain financial targets are achieved, vested shares may range from zero percent to 200 percent of the original award amount.

Note 8. Inventories

Inventories at September 30, 2006 and December 31, 2005 are:

	September 30, 2006	December 31, 2005
	(Millions)	
Natural gas in underground storage	$ 93.1	$ 90.4
Materials, supplies and other	86.7	82.2
Natural gas liquids	80.4	100.0
	$ 260.2	$ 272.6

Note 9. Debt and Banking Arrangements

Long-Term Debt

Revolving credit and letter of credit facilities (credit facilities)

In May 2006, we obtained an unsecured, three-year, $1.5 billion revolving credit facility, replacing our $1.275 billion secured revolving credit facility. The new unsecured facility contains similar terms and financial covenants as the secured facility, but contains additional restrictions on asset sales, certain subsidiary debt and sale-leaseback transactions. The facility is guaranteed by Williams Gas Pipeline Company, LLC and we guarantee obligations of Williams Partners L.P. for up to $75 million. Northwest Pipeline Corporation (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. Interest is calculated based on a choice of two methods: a fluctuating rate equal to the lender s base rate plus an applicable margin or a periodic fixed rate equal to LIBOR plus an applicable margin. We are required to pay a commitment fee (currently .25 percent annually) based on the unused portion of the facility. The margins and commitment fee are generally based on the specific borrower s senior unsecured long-term debt ratings. Significant financial covenants under the credit agreement include the following:

Our ratio of debt to capitalization must be no greater than 65 percent;

Ratio of debt to capitalization must be no greater than 55 percent for Northwest Pipeline and Transco;

Notes (Continued)

Our ratio of EBITDA to interest, on a rolling four quarter basis, must be no less than 2.5 for the period ending December 31, 2007 and 3.0 for the remaining term of the agreement.

At September 30, 2006, no loans are outstanding under our credit facilities. Letters of credit issued under our credit facilities are:

	Letters of Credit at September 30, 2006 (Millions)
$500 million unsecured credit facilities	$ 436.5
$700 million unsecured credit facilities	$ 505.6
$1.5 billion unsecured credit facility	$ 45.6

Issuances and retirements

On May 28, 2003, we issued $300 million of 5.5 percent junior subordinated convertible debentures due 2033. These notes, which are callable after seven years, are convertible at the option of the holder into our common stock at a conversion price of approximately $10.89 per share. In November 2005, we initiated an offer to convert these debentures to shares of our common stock. In January 2006, we converted approximately $220.2 million of the debentures (see Note 10).

In April 2006, Transco issued $200 million aggregate principal amount of 6.4 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement. In October 2006, Transco completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

In April 2006, we retired a secured floating-rate term loan for $488.9 million, including outstanding principal and accrued interest. The loan was due in 2008 and secured by substantially all of the assets of Williams Production RMT Company. The loan was retired using a combination of cash and revolving credit borrowings.

In June 2006, Williams Partners L.P. completed its acquisition of 25.1 percent of our interest in Williams Four Corners LLC for $360 million. The acquisition was completed after successfully closing a $150 million private debt offering of 7.5 percent senior unsecured notes due 2011 and an equity offering of approximately $225 million in net proceeds. The debt and equity issued by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively. Williams Four Corners LLC owns certain gathering, processing and treating assets in the San Juan Basin in Colorado and New Mexico.

In June 2006, Northwest Pipeline issued $175 million aggregate principal amount of 7 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement. In October 2006, Northwest Pipeline completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

Note 10. Stockholders Equity

In November 2005, we initiated an offer to convert our 5.5 percent junior subordinated convertible debentures into our common stock. In January 2006, we converted approximately $220.2 million of the debentures in exchange for 20.2 million shares of common stock, a $25.8 million cash premium, and $1.5 million of accrued interest.

Note 11. Contingent Liabilities and Commitments

Rate and Regulatory Matters and Related Litigation

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result of rulings in certain of these proceedings, a portion of the revenues of these subsidiaries has been collected subject to refund. The natural gas pipeline subsidiaries have accrued approximately $7 million for potential refunds as of September 30, 2006.

Issues Resulting From California Energy Crisis

Subsidiaries of our Power segment are 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 states in

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Notes (Continued)

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. Certain issues, however, 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. We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable totaling approximately $29 million at September 30, 2006. Collection of the interest 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 proceeding, including the refund period, were made to the Ninth Circuit Court of Appeals. 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. Because of our settlement, we do not expect this decision will have a material impact on us. As part of the State Settlement, an additional $60 million, previously accrued, remains to be paid to the California Attorney General (or his designee) over the next four years, with the final payment of $15 million due on January 1, 2010.

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 Power have pled guilty to manipulation of gas prices through misreporting to an industry trade periodical. On February 21, 2006, we entered into a deferred prosecution agreement with the Department of Justice (DOJ) that is intended to resolve this matter. The agreement obligated us to pay a total of $50 million, of which $20 million was paid in March 2006. The remaining $30 million must be paid by March 2007. Absent a breach, the agreement will expire 15 months from the date of execution and no further action will be taken 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. We have reached settlement of this matter for $2.4 million. Legal documents will be filed with the court and the settlement is subject to court approval.

- Class action litigation in state court in California alleging that we manipulated prices for indirect purchasers of gas in California. The court granted preliminary approval of our settlement of this matter for $15.6 million, and we paid this amount into escrow on September 5, 2006 pending final approval.

- State court in California on behalf of certain individual gas users.

- Class action litigation in state court in Colorado, Kansas, and Tennessee brought on behalf of indirect purchasers of gas in those states.

Earlier this year, we settled a case for $9.15 million in Federal court in New York based on an allegation of manipulation of the NYMEX gas market. 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.

Notes (Continued)

Mobile Bay Expansion

In December 2002, an administrative law judge at the FERC issued an initial decision in Transco s 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. Power 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, Power could have been subject to surcharges of approximately $91 million, excluding interest, through September 30, 2006, 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 has demanded repayment of the purchase price for the reduced portions of the claims. We have disputed the amount of the claim and are negotiating with the purchaser regarding potential payment 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 programs 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, 2006, we had accrued liabilities of $12 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-1980 s, 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-ups in Washington. Currently, Northwest Pipeline is assessing the actions needed for the sites to comply with Washington s current environmental standards. At September 30, 2006, we have accrued liabilities totaling approximately $5 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, 2006, we have accrued liabilities totaling approximately $6 million for these costs.

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Notes (Continued)

In August 2005, our subsidiary, Williams Production RMT Company, voluntarily disclosed to the Colorado Department of Public Health and Environment (CDPHE) two air permit violations. In October 2005, the CDPHE responded to our disclosure indicating that penalty immunity is not available in the matter and that it will seek resolution through a Compliance Order on Consent. We continue to believe that our voluntary self-evaluation and disclosure qualifies for penalty immunity. Negotiations with the CDPHE are ongoing.

In March 2006, the CDPHE issued a notice of violation (NOV) to Williams Production RMT Company related to our operating permit for the Rulison oil separation and evaporation facility. On April 12, 2006, we met with the CDPHE to discuss the allegations contained in the NOV. In May 2006, we provided additional information to the agency regarding the emission estimates for operations from 1997 through 2003 and applied for updated permits.

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. On September 13, 2006, we met with the CDPHE to discuss the allegations contained in the NOV, and we will provide additional requested information to the agency.

In August 2006, the CDPHE issued a NOV to Williams Production RMT Company related to our Grand Valley Oil Separation and Evaporation 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. On September 19, 2006, we met with the CDPHE and will provide additional requested information to the agency.

On July 2, 2001, the EPA issued an information request asking 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. On March 11, 2004, the DOJ invited the new owner of Williams Energy Partners, Magellan Midstream Partners, L.P. (Magellan), to enter into negotiations regarding alleged violations of the Clean Water Act and to sign a tolling agreement. No penalty has been assessed by the EPA; however, the DOJ stated in its letter that the maximum possible penalties were approximately $22 million for the alleged violations. It is anticipated that by providing additional clarification and through negotiations with the EPA and DOJ, that any proposed penalty will be reduced. All our environmental indemnity obligations to Magellan were released in a May 26, 2004 buyout. After previous negotiations with the DOJ related to four release events not related to Magellan-owned assets and a subsequent year-long absence of activity, in April 2006, the DOJ asked us to discuss the Magellan obligations and our obligations including two 2006 spills at our Colorado and Wyoming facilities. On July 18, 2006, Williams provided information as requested to the DOJ regarding the 2006 spills.

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.

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, 2006, we have accrued liabilities of approximately $9 million for such excess costs.

We were involved in a dispute with a defendant in two class action damages lawsuits in Florida state court involving this former chemical fertilizer business. Settlement of both class actions was judicially approved in October 2004. We were not a named defendant in the settled lawsuits, but have contractual obligations to participate with the named defendants in the ongoing environmental remediation. One defendant sought indemnification of approximately $20 million from us as a result of the settlement. In November 2005, the court ordered us to arbitrate the indemnification dispute with the one defendant. The hearing before the arbitrator occurred on June 26, 2006. On July 5, 2006, the arbitrator ruled in favor of the one defendant, awarding its full claim of approximately $20 million to be paid by us. As a result, we recorded a pre-tax charge of $19.2 million within discontinued operations in the second quarter of 2006.

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Notes (Continued)

Other

At September 30, 2006, we have accrued environmental liabilities totaling approximately $25 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 had 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 2004, Williams Refining and the new owner of the Memphis refinery met with the EPA and the DOJ to discuss alleged violations and proposed penalties due to noncompliance issues identified in the report, including the benzene NESHAP issue. In July 2006, we finalized our agreements 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. The total settlement of approximately $3 million was fully accrued in the second quarter of 2006.

In 2004, the Oklahoma Department of Environmental Quality (ODEQ) issued a NOV alleging various air permit violations associated with our operation of the Dry Trail gas processing plant prior to our sale of the facility. The NOV was issued to our subsidiary, Williams Field Services Company, and the purchaser of the plant. On April 14, 2005, the ODEQ issued a letter to the current Dry Trail plant owners assessing a penalty under the NOV of approximately $750,000, and the current owner asserted an indemnification claim to us for payment of the penalty. We and the current owner entered into an indemnity settlement under which we are responsible for payment of the penalty while the current owner is responsible for all forward costs of compliance. On June 2006, we settled all issues with the ODEQ, and have paid approximately $400,000 to settle the penalty. This matter is now resolved.

In 2004, our Gulf Liquids subsidiary initiated a self-audit of all environmental conditions (air, water, waste) at three facilities: 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). No specific penalty amount was assessed. Instead, LDEQ was required by Louisiana law to demand a profit and loss statement to determine the financial benefit obtained by noncompliance and to assess a penalty accordingly. Gulf Liquids offered $91,500 as a single, final, global multi-media settlement. Subsequent negotiations have resulted in a revised offer of $109,000, which LDEQ is currently reviewing.

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.

Notes (Continued)

Other Legal Matters

Royalty indemnifications

In 1996, a producer asserted a claim for damages against our Transco subsidiary for indemnification relating to prior royalty payments. The Louisiana Court of Appeals denied the producer s appeal and affirmed a lower court s judgment in favor of Transco. On March 31, 2006, the Louisiana Supreme Court denied the producer s request for further review (see Note 3).

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 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 on April 1, 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 was declining to 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. On October 20, 2006, the District Court dismissed all claims against us and our wholly owned subsidiaries.

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 BTU 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.

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Notes (Continued)

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 allege that we and co-defendants, WilTel Communications (WilTel), previously an owned subsidiary known as Williams Communications, and certain corporate officers, have acted jointly and separately to inflate the stock price of both companies. Other suits allege similar causes of action related to a public offering in early January 2002 known as the FELINE PACS offering. These cases were also filed in 2002 against us, certain corporate officers, all members of our board of directors and all of the offerings underwriters. WilTel is no longer a defendant as a result of its bankruptcy. These cases have all been consolidated and an order has been 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 are currently covering 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 Power. On June 13, 2006, we announced that we had reached an agreement-in-principle to settle the claims of our securities holders for a total payment of $290 million. On October 4, 2006, the court granted preliminary approval of the settlement, and the settlement amount will be paid into escrow pending final approval. Of the total settlement amount, we expect to pay approximately $145 million in cash to fund the settlement, and expect the balance to be funded by our insurers. The exact amount of our payment is subject to final determination and timing of certain insurer coverage allocations. The court has set a hearing on the fairness of the settlement on February 9, 2007. We have 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 as we believe the likelihood of any future performance is remote. As of September 30, 2006, we have recorded pre-tax charges of approximately $165 million for this settlement and related legal costs.

Settlement discussions with the WilTel equity holders are ongoing, and the trial has been set to begin on January 17, 2007. Any obligation of ours to the WilTel equity holders as a result of a settlement or as a result of trial will not likely be covered by insurance, as we expect our insurance coverage to be fully utilized for the settlement described above. The extent of the obligation is presently unknown and cannot be estimated, but it is reasonably possible that our exposure materially exceeds amounts accrued for this matter.

Derivative shareholder suits have been filed in state court in Oklahoma all based on similar allegations. The state court approved motions to consolidate and to stay these Oklahoma suits pending action by the federal court in the shareholder suits. On July 17, 2006, we reached an agreement-in-principle to settle the derivative suits. Under the terms of this settlement, we agreed to certain corporate governance and internal control enhancements, which have already been implemented, and to reimburse the plaintiffs attorney fees and expenses in an amount not to exceed $1.2 million which will be covered by insurance. On October 24, 2006, the court held its hearing on the fairness of the settlement and issued its final approval.

Federal income tax litigation

One of our wholly-owned subsidiaries, Transco Coal Gas Company, is engaged in a dispute with the Internal Revenue Service (IRS) regarding the recapture of certain income tax credits associated with the construction of a coal gasification plant in North Dakota by Great Plains Gasification Associates, in which Transco Coal Gas Company was a partner. The IRS has taken alternative positions that allege a disposition date for purposes of tax credit recapture that is earlier than the position taken in the partnership tax return. On August 23, 2001, we filed a petition in the U.S. Tax Court to contest the adjustments to the partnership tax return proposed by the IRS. Certain settlement discussions have taken place since that date. During the fourth quarter of 2004, we determined that a reasonable settlement with the IRS could not be achieved. We filed a Motion for Summary Judgment with the Tax Court, which was heard, and denied, in January 2005. The matter was then tried before the Tax Court in February 2005. We continue to believe that the return position of the partnership is with merit. However, it is reasonably possible that the Tax Court could render an unfavorable decision that could ultimately result in estimated income taxes and interest of up to approximately $115 million in excess of the amount currently accrued.

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

Notes (Continued)
Trans-Alaska Pipeline System (TAPS) Quality Bank. Primary issues being litigated include the appropriate valuation of the naphtha, heavy distillate, vacuum gas oil and residual product cuts within the TAPS Quality Bank as well as the appropriate retroactive effects of the determinations. Due to the sale of WAPI s interests on March 31, 2004, no future Quality Bank liability will accrue but we are responsible for any liability that existed as of that date including potential liability for any retroactive payments that might be awarded in these proceedings for the period prior to March 31, 2004. In the third quarter of 2004, the FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions. The initial decisions set forth methodologies for determining the valuations of the product cuts under review and also approved the retroactive application of the approved methodologies for the heavy distillate and residual product cuts. In 2004, we accrued approximately $134 million based on our computation and assessment of ultimate ruling terms that were considered probable.

The FERC and the RCA completed their reviews of the initial decisions and in 2005 issued substantially similar orders generally affirming the initial decisions. On June 1, 2006, the FERC, after two sets of rehearing requests, entered its final order (FERC Final Order). During this administrative rehearing process all other appeals of the initial decisions were stayed including ExxonMobil s appeal to the D.C. Circuit Court of Appeals asserting 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. ExxonMobil filed a similar appeal in the Alaska Superior Court. We also appealed the FERC s order to the extent of its ruling on the West Coast Heavy Distillate component.

The Quality Bank Administrator issued his interpretations of the payment obligations under the FERC Final Order, and we and others filed exceptions to these instructions with the FERC. We expect the FERC s ruling on these payment instruction exceptions later in the fourth quarter of 2006. Once the FERC rules, the Administrator will invoice us for amounts due, and we will be required to pay the invoiced amounts, subject to the outcome of the appeals of the FERC Final Order. We estimate that our net obligation could be as much as $115 million. Amounts accrued in excess of this estimated obligation will be retained pending resolution of all appeals.

Redondo Beach taxes

On February 5, 2005, Power received a tax assessment letter, addressed to AES Redondo Beach, L.L.C. and Power, 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 and on September 23, 2005, the tax administrator for the city issued a decision in which he found Power jointly and severally liable with AES Redondo Beach for back taxes of approximately $36 million and interest and penalties of approximately $21 million. Both we and AES Redondo Beach have filed notices of appeal that will be heard at the city level. On October 20, 2006, the city hearing officer for the appeal of the pre-2005 amounts issued a draft decision affirming our utility users tax liability and reversing AES Redondo s liability because the officer ruled that AES Redondo is an exempt public utility. Before a final decision, we have an opportunity to present oral arguments on the draft decision at a hearing that has not been scheduled. Upon final determination, we may be required to pay the full amount of any final determination prior to further appeal to the California state courts.

Since the first assessment in 2005, we have received subsequent assessments (for the periods October 2004 through June 2006) totaling approximately $4 million (inclusive of interest and penalties). We have protested all these assessments and requested hearings on them. We and AES Redondo have also filed separate refund actions in Los Angeles Superior Court related to certain taxes paid since the initial 2005 notice of assessment. We believe that under our tolling agreement related to the Redondo Beach generating facility, AES Redondo Beach is responsible for taxes of the nature asserted by the city; however, AES Redondo Beach has notified us that it does not agree.

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

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Louisiana and Texas. In January 2002, NAICO added Gulf Liquids co-venturer Power 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 Power and Gulf Liquids on July 31, 2006 and its related punitive damages verdict on August 1, 2006. The court is not expected to enter any judgment until the first quarter of 2007. Based on our interpretation of the jury verdicts, we have estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $20.6 million, all of which have been accrued as of September 30, 2006. In addition, it is reasonably possible that any ultimate judgment may include additional amounts of approximately $185 million in excess of our accrual, which primarily represents our estimate of potential punitive damage exposure under Texas law. In addition, the court could award up to $13 million in attorneys fees.

Hurricane lawsuits

We were named as a defendant in two class action petitions for damages filed in the United States District Court for the Eastern District of Louisiana in September and October 2005 arising from hurricanes that struck Louisiana in 2005. The class action plaintiffs, purporting to represent persons, businesses and entities in the State of Louisiana who have suffered damage as a result of the winds and storm surge from the hurricanes, allege that the operating activities of the two sub-classes of defendants, which are all oil and gas pipelines that dredged pipeline canals or installed pipelines in the marshes of south Louisiana (including Transco) and all oil and gas exploration and production companies which drilled for oil and gas or dredged canals in the marshes of south Louisiana, have altered marshland ecology and caused marshland destruction which otherwise would have averted all or almost all of the destruction and loss of life caused by the hurricanes. Plaintiffs requested that the court allow the lawsuits to proceed as class actions and sought legal and equitable relief in an unspecified amount. On September 28, 2006, the court granted our and the other defendants joint motion to dismiss the class action petitions on various grounds. In August 2006, an additional class action case containing substantially identical allegations was filed against the same defendants, including Transco. On October 20, 2006, we filed a motion to dismiss this latest case on the same basis as the motion filed in the earlier cases.

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 $21 to $24 million in taxes and interest from 2000 through September 30, 2006.

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 an unspecified amount of damages and our specific performance under certain guarantees. On September 1, 2006, we filed our answer to the purchaser s complaint denying all liability. The Texas court has denied our request to stay further proceedings against us pending the resolution of our prior suit filed against the purchaser in Delaware state court regarding the same matters.

At September 30, 2006, 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.

Notes (Continued)

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

Power 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, 2006, Power s estimated committed payments under these contracts range from approximately $87 million to $424 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 $5.6 billion.

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, Power, 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.

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 $17 million on behalf of ACCROVEN. These expire in January 2007 and have no carrying value.

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 $46 million at September 30, 2006. Our exposure declines systematically throughout the remaining term of WilTel s obligations. The carrying value of these guarantees is approximately $42 million at September 30, 2006.

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, 2006.

Notes (Continued)

Former managing directors of Gulf Liquids have been 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 might 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.

Note 12. Comprehensive Income (Loss)

Comprehensive income (loss) is as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(Millions)		(Millions)	
Net income	$ 106.2	$ 4.4	$ 162.1	$ 246.8
Other comprehensive income (loss):				
Unrealized gains (losses) on derivative instruments	130.7	(390.3)	364.9	(663.2)
Net reclassification into earnings of derivative instrument losses	77.5	65.2	211.8	187.7
Foreign currency translation adjustments	.4	14.7	10.7	9.6
Minimum pension liability adjustment		.8	(.3)	.8
Other comprehensive income (loss) before taxes	208.6	(309.6)	587.1	(465.1)
Income tax (provision) benefit on other comprehensive income (loss)	(79.7)	124.4	(220.6)	181.9
Other comprehensive income (loss)	128.9	(185.2)	366.5	(283.2)
Comprehensive income (loss)	$ 235.1	$ (180.8)	$ 528.6	$ (36.4)

Unrealized gains (losses) on derivative instruments represents changes in the fair value of certain derivative contracts that have been designated as cash flow hedges. The net unrealized gains for the nine months ending September 30, 2006, include net unrealized gains on forward power purchases and sales of approximately $114 million, net unrealized gains on forward natural gas purchases and sales of approximately $261 million, and net unrealized losses on forward natural gas liquids sales of approximately $10 million. *Unrealized gains (losses) on derivative instruments* for the three and nine months ending September 30, 2006 and 2005 are primarily due to the effect of changes in the forward prices of these commodities relative to our hedge position.

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 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.

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Note 13. Segment Disclosures

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. 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 (losses)* and *income (loss) 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 Power segment which, in turn, enters into offsetting derivative contracts with unrelated third parties. Power bears the counterparty performance risks associated with unrelated third parties. External revenues of our Exploration & Production segment include third-party oil and gas sales, more than offset by transportation expenses and royalties due third parties on intersegment sales.

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

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Power	Other	Eliminations	Total
				(Millions)			
Three months ended September 30, 2006							
Segment revenues:							
External	$ (54.5)	$ 331.6	$ 1,104.1	$ 1,916.5	$ 2.3	$	$ 3,300.0
Internal	425.6	2.6	12.9	187.6	4.1	(632.8)	
Total revenues	$ 371.1	$ 334.2	$ 1,117.0	$ 2,104.1	$ 6.4	$ (632.8)	$ 3,300.0
Segment profit (loss)	$ 144.5	$ 109.0	$ 212.2	$ (69.7)	$ (.2)	$	$ 395.8
Less:							
Equity earnings	5.6	9.2	7.3	7.6	.2		29.9
Income from investments		.5					.5
Segment operating income (loss)	$ 138.9	$ 99.3	$ 204.9	$ (77.3)	$ (.4)	$	365.4
General corporate expenses							(35.0)
Securities litigation settlement and related costs							(3.4)
Consolidated operating income							$ 327.0
Three months ended September 30, 2005							
Segment revenues:							
External	$ (52.0)	$ 344.3	$ 744.5	$ 2,043.4	$ 2.1	$	$ 3,082.3

Internal	370.4	1.5	10.2	199.5	4.2	(585.8)	
Total revenues	$ 318.4	$ 345.8	$ 754.7	$ 2,242.9	$ 6.3	$ (585.8)	$ 3,082.3
Segment profit (loss)	$ 158.8	$ 161.1	$ 121.1	$ (226.4)	$ (10.1)	$	$ 204.5
Less:							
Equity earnings (losses)	5.8	17.0	3.2	1.0	(9.4)		17.6
Segment operating income (loss)	$ 153.0	$ 144.1	$ 117.9	$ (227.4)	$ (0.7)	$	186.9
General corporate expenses							(42.8)
Consolidated operating income							$ 144.1

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Notes (Continued)

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Power (Millions)	Other	Eliminations	Total
Nine months ended September 30, 2006							
Segment revenues:							
External	$ (149.9)	$ 995.9	$ 3,099.8	$ 5,089.4	$ 7.4	$	$ 9,042.6
Internal	1,219.3	9.6	40.1	674.9	12.4	(1,956.3)	
Total revenues	$ 1,069.4	$ 1,005.5	$ 3,139.9	$ 5,764.3	$ 19.8	$ (1,956.3)	$ 9,042.6
Segment profit (loss)	$ 411.9	$ 366.4	$ 494.4	$ (171.8)	$ .1	$	$ 1,101.0
Less:							
Equity earnings	16.5	27.4	23.4	7.7	.2		75.2
Segment operating income (loss)	$ 395.4	$ 339.0	$ 471.0	$ (179.5)	$ (.1)	$	1,025.8
General corporate expenses							(99.3)
Securities litigation settlement and related costs							(165.3)
Consolidated operating income							$ 761.2
Nine months ended September 30, 2005							
Segment revenues:							
External	$ (120.3)	$ 1,029.4	$ 2,309.5	$ 5,682.4	$ 6.5	$	$ 8,907.5
Internal	969.2	8.7	32.3	624.8	12.9	(1,647.9)	
Total revenues	$ 848.9	$ 1,038.1	$ 2,341.8	$ 6,307.2	$ 19.4	$ (1,647.9)	$ 8,907.5
Segment profit (loss)	$ 380.8	$ 493.0	$ 358.8	$ (187.3)	$ (74.7)	$	$ 970.6
Less:							
Equity earnings (losses)	12.9	36.3	14.4	3.0	(21.5)		45.1
Income (loss) from investments			.7		(49.1)		(48.4)
Segment operating income (loss)	$ 367.9	$ 456.7	$ 343.7	$ (190.3)	$ (4.1)	$	973.9
General corporate expenses							(106.3)
Consolidated operating income							$ 867.6

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

Total Assets

	September 30, 2006	December 31, 2005
	(Millions)	
Exploration & Production	$ 7,464.9	$ 8,672.0
Gas Pipeline (1)	8,253.1	7,581.0
Midstream Gas & Liquids	5,121.6	4,677.7
Power (2)	7,877.4	14,989.2
Other	3,531.0	3,929.9
Eliminations (3)	(7,431.8)	(10,420.0)
	24,816.2	29,429.8
Assets of discontinued operations	5.3	12.8
Total	$ 24,821.5	$ 29,442.6

(1) Total assets for the Gas Pipeline segment as of September 30, 2006, include an increase to the balance of *property, plant and equipment - net* of approximately $88 million. The increase relates to certain revisions in estimates for both the timing and cost of asset retirement obligations for certain offshore assets. *Other liabilities and deferred income* was increased by the same amount.

(2) The decrease in Power s total assets is due primarily to a decrease in derivative assets as a result of the

impact of changes in commodity prices on existing forward derivative contracts. Power s derivative assets are substantially offset by their derivative liabilities.

(3) The decrease in Eliminations is due primarily to a decrease in the intercompany derivative balances.

Note 14. Recent Accounting Standards

In September 2005, the FASB ratified EITF Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty (EITF 04-13). The consensus states that two or more inventory purchase and sales transactions with the same counterparty that are entered into in contemplation of one another should be combined as a single exchange transaction for purposes of applying APB Opinion No. 29, Accounting for Nonmonetary Transactions. A nonmonetary exchange of inventory within the same line of business where finished goods inventory is transferred in exchange for the receipt of either raw materials or work in process inventory should be recognized at fair value by the entity transferring the finished goods inventory if fair value is determinable within reasonable limits and the transaction has commercial substance. All other nonmonetary exchanges of inventory within the same line of business should be recognized at the carrying amount of the inventory transferred. EITF 04-13 is effective for new arrangements entered into, and modifications or renewals of existing arrangements, beginning in the first reporting period beginning after March 15, 2006. We applied this Issue during 2006 with no material impact on our Consolidated Financial Statements.

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In February 2006, the FASB issued Statement of Financial Accounting Standard (SFAS) No. 155, Accounting for Certain Hybrid Financial Instruments, an amendment of FASB Statements No. 133 and 140 (SFAS No. 155). With regard to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, (SFAS No. 133) this Statement permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, clarifies which interest-only and principal-only strips are not subject to the requirements of SFAS No. 133, and requires the holder of an interest in securitized financial assets to determine whether the interest is a freestanding derivative or contains an embedded derivative requiring bifurcation. SFAS No. 155 also amends SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, (SFAS No. 140) to eliminate a restriction on the passive derivative financial instruments that a qualifying special purpose entity may hold. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. We will assess the impact of this Statement on our Consolidated Financial Statements.

In March 2006, the FASB issued SFAS No. 156, Accounting for Servicing of Financial Assets, an amendment of FASB Statement No. 140 (SFAS No. 156). This Statement amends SFAS No. 140 with respect to the accounting for separately recognized servicing assets and liabilities from undertaking an obligation to service a financial asset by entering into a servicing contract. SFAS No. 156 is effective as of the beginning of an entity s first fiscal year that begins after September 15, 2006. We will assess the impact of this Statement on our Consolidated Financial Statements.

In April 2006, the FASB issued a Staff Position (FSP) on a previously issued Interpretation (FIN), FSP FIN 46(R)-6, Determining the Variability to Be Considered in Applying FASB Interpretation No. 46(R). When determining the variability of an entity in applying FIN 46(R), a reporting enterprise must analyze the design of the entity and consider the nature of the risks in the entity, and determine the purpose for which the entity was created and determine the variability the entity is designed to create and pass along to its interest holders. The FSP is effective beginning in the third quarter of 2006 on a prospective basis. We applied this FSP with no material impact on our Consolidated Financial Statements.

In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109 (FIN 48). The Interpretation clarifies the accounting for uncertainty in income taxes under FASB Statement No. 109, Accounting for Income Taxes. 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.

FIN 48 is effective for fiscal years beginning after December 15, 2006. The cumulative effect of applying the Interpretation must be reported as an adjustment to the opening balance of retained earnings in the year of adoption. We will adopt the Interpretation beginning in 2007 and will adjust the January 1, 2007 opening balance of retained earnings. We are currently assessing the impact of the Interpretation on our Consolidated Financial Statements but we do not expect a material impact on our financial position due to the adoption of this FIN.

In June 2006, the FASB ratified EITF No. 06-3 How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation) (EITF 06-3). EITF 06-3 addresses the income statement presentation of any tax collected from customers and remitted to a government authority and concludes the presentation of taxes on either a gross basis or a net basis is an accounting policy decision that should be disclosed pursuant to APB Opinion No. 22 Disclosure of Accounting Policies. This is effective for interim and annual reporting periods beginning after December 15, 2006 and will require the financial statement disclosure of any significant taxes recognized on a gross basis. We are reviewing our presentation in our Consolidated Financial Statements and will adopt the provisions of this EITF beginning in 2007.

In September 2006, the FASB issued 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 single definition of fair value, provides guidance on the methods used to estimate fair value and increases disclosures about estimates of fair value. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 and is generally applied prospectively. We will assess the impact of this Statement on our Consolidated Financial Statements.

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Notes (Continued)

The FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106 and 132(R) (SFAS No. 158) in September 2006. The Statement requires an employer to recognize in its statement of financial position an asset for a defined benefit pension or other postretirement benefit plan s overfunded status or a liability for a plan s underfunded status. Entities will now recognize in the statement of financial position changes in the funded status of a defined benefit pension or other postretirement benefit plan in the year in which the changes occur. Those changes that arise during the year, but are not recognized as a component of net periodic benefit cost, will be reported in *other comprehensive income*. The Statement also requires measurement of a plan s assets and its obligations that determine its funded status as of the end of the employer s fiscal year. The requirement to recognize the funded status of a defined benefit plan and the related disclosure requirements is effective as of the end of the fiscal year ending after December 15, 2006. The initial impact of this Statement on our Consolidated Financial Statements will not be determined until our Plans benefit obligations and the fair value of our Plans assets are measured as of December 31, 2006. In general, we expect the impact of this statement to decrease total assets, increase total liabilities and decrease *stockholders equity*, as a charge to *accumulated other comprehensive income (loss)*, on our Consolidated Balance Sheet. Adoption of the Statement is not expected to impact our Consolidated Statement of Income or funding requirements. Estimates based upon January 1, 2006, data indicate that the decrease in our pension and other postretirement benefit assets and the increase in our pension and other postretirement benefit liabilities could potentially total approximately $350 million due to the adoption of this Statement. The actual adjustments ultimately recorded will depend on various factors including, but not limited to, regulatory accounting interpretations, changes in assumptions used to calculate the year-end benefit obligations, changes in the fair value of plan assets at year-end, and the impact of income taxes. We will disclose the funded status and provide the new required disclosures in our December 31, 2006, Consolidated Financial Statements. The requirement to measure plan assets and benefit obligations as of the date of the employer s fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008, and will not impact our Consolidated Financial Statements as we currently measure our Plans obligations and assets as of our fiscal year-end.

In September 2006, the FASB issued FSP AUG AIR-1, Accounting for Planned Major Maintenance Activities (FSP AUG AIR-1). This FSP addresses the planned major maintenance of assets and prohibits the use of the accrue-in-advance method of accounting for these activities in annual and interim reporting periods. The FSP continues to allow the direct expense, built-in overhaul and deferral methods. FSP AUG AIR-1 requires disclosure of the method of accounting for planned major maintenance activities as well as information related to the change from the accrue-in-advance method to another method. This FSP is effective for the first fiscal year beginning after December 15, 2006 and should be applied retrospectively. Early adoption is permitted as of the beginning of an entity s fiscal year. We are assessing the impact of this FSP on our Consolidated Financial Statements but we do not expect a material impact on our financial position due to the adoption of this FSP.

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

Company Outlook

Our plan for 2006 is focused on continued disciplined growth. 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.
- Accelerate additional asset transactions between us and Williams Partners L.P., our master limited partnership.
- Increase the scale of our gathering and processing business in key growth basins.
- File new rates to enable our Gas Pipeline segment to remain competitive and value-creating, while managing our costs and capturing demand growth. These rates will be effective, subject to refund, in 2007.
- Execute power contracts that offset a significant percentage of our financial obligations associated with our tolling agreements.

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 11 of Notes to Consolidated Financial Statements); and
- 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, 2006, decreased $71.3 million from the nine months ended September 30, 2005. The decrease was primarily due to our securities litigation settlement and an accrual for a Gulf Liquids litigation contingency and related interest. These decreases were partially offset by favorable natural gas liquids margins and higher fee revenues from our deepwater facilities at Midstream and the benefit of increased natural gas production at Exploration & Production. See additional discussion in Results of Operations.

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Management s Discussion and Analysis (Continued)

Recent Events

Third Quarter 2006

In September 2006, Transco offered to exchange all of its privately placed outstanding 6.4 percent notes due 2016 for substantially identical notes registered under the Securities Act of 1933, as amended. This exchange was successfully completed in October 2006.

In September 2006, Northwest Pipeline Corporation offered to exchange all of its privately placed outstanding 7 percent senior notes due 2016 for substantially identical notes registered under the Securities Act of 1933, as amended. This exchange was successfully completed in October 2006.

Northwest Pipeline and Transco have each filed a general rate case with the Federal Energy Regulatory Commission (FERC). The new transportation and storage rates for both pipelines will be effective, subject to refund, in the first quarter of 2007.

Second Quarter 2006

In April 2006, Transco issued $200 million aggregate principal amount of 6.4 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement. See additional discussion in *Third Quarter 2006*.

In April 2006, we retired a secured floating-rate term loan for $488.9 million, including outstanding principal and accrued interest. The loan was due in 2008 and secured by substantially all of the assets of Williams Production RMT Company. The loan was retired using a combination of cash and revolving credit borrowings.

In May 2006, we replaced our $1.275 billion secured revolving credit facility with a $1.5 billion unsecured revolving credit facility. The new facility contains similar terms and financial covenants as the secured facility, but contains certain additional restrictions (see Note 9 of Notes to Consolidated Financial Statements).

In May 2006, our Board of Directors approved a regular quarterly dividend of 9 cents per share of common stock, which reflects an increase of 20 percent compared with the 7.5 cents per share paid in each of the three prior quarters.

In June 2006, Northwest Pipeline Corporation issued $175 million aggregate principal amount of 7 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement. See additional discussion in *Third Quarter 2006*.

In June 2006, Williams Partners L.P. completed its acquisition of 25.1 percent of our interest in Williams Four Corners LLC for $360 million. The acquisition was completed after successfully closing a $150 million private debt offering of senior unsecured notes due 2011 and an equity offering of approximately $225 million in net proceeds. The debt and equity issued by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively. Williams Four Corners LLC owns certain gathering, processing and treating assets in the San Juan Basin in Colorado and New Mexico.

In June 2006, we reached an agreement-in-principle to settle class-action securities litigation filed on behalf of purchasers of our securities between July 24, 2000, and July 22, 2002, for a total payment of $290 million to plaintiffs, subject to court approval. We plan to fund the settlement from a combination of insurance proceeds and cash on hand. We recorded a pre-tax charge for approximately $161 million in second-quarter 2006. This settlement will not have a material effect on our liquidity position.

On July 31, 2006, and August 1, 2006, we received a verdict in civil litigation related to a contractual dispute surrounding certain natural gas processing facilities known as Gulf Liquids. We recorded a pre-tax charge for approximately $88 million in second quarter 2006 related to this loss contingency (see Note 11 of Notes to Consolidated Financial Statements).

Our property insurance coverage levels and premiums were revised during second quarter of 2006. In general, our coverage levels have decreased while our premiums have increased. These changes reflect general trends in our industry due to hurricane-related damages in recent years.

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Management s Discussion and Analysis (Continued)

First Quarter 2006

In November 2005, we initiated an offer to convert our 5.5 percent junior subordinated convertible debentures into our common stock. In January 2006, we converted approximately $220.2 million of the debentures in exchange for 20.2 million shares of common stock, a $25.8 million cash premium, and $1.5 million of accrued interest.

General

Unless indicated otherwise, the following discussion and analysis of Results of Operations and Financial Condition relates to our continuing operations and should be read in conjunction with the Consolidated Financial Statements and notes thereto included in Item 1 of this document and our 2005 Annual Report on Form 10-K.

Accounting for Stock-Based Compensation

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123 (Revised 2004), Share-Based Payment (SFAS No 123 (R)). The Statement, which we adopted effective January 1, 2006, requires that compensation costs for all share-based awards to employees be recognized in the Consolidated Statement of Income based on their fair values. Prior to January 1, 2006, we accounted for share-based awards to employees by applying the intrinsic value method in accordance with Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and, as such, did not generally recognize compensation cost for employee stock options. We adopted SFAS No. 123(R) using the modified-prospective method. Under this method, compensation cost recognized for the three and nine months ended September 30, 2006, was $11.1 million and $32.5 million, respectively, approximately $4 million and $15 million of which is related to stock options. Compensation cost recognized for the three and nine months ended September 30, 2005, prior to the adoption of SFAS No. 123(R), was $4.2 million and $10.4 million, respectively. Measured but unrecognized compensation cost at September 30, 2006, was approximately $61 million, which does not include the effect of estimated forfeitures of $2.2 million. This amount is comprised of approximately $17 million related to stock options and approximately $44 million related to deferred shares. These amounts are expected to be recognized over a weighted-average period of 1.8 years. See Note 7 of Notes to Consolidated Financial Statements for additional information.

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Management s Discussion and Analysis (Continued)

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, 2006, compared to the three and nine months ended September 30, 2005. 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,			
	2006	2005	$ Change from 2005	% Change from 2005*	2006	2005	$ Change from 2005	% Change from 2005*
	(Millions)				(Millions)			
Revenues	$ 3,300.0	$ 3,082.3	$ 217.7	+7%	$ 9,042.6	$ 8,907.5	$ 135.1	+2%
Costs and expenses:								
Costs and operating expenses	2,822.4	2,826.2	3.8		7,684.9	7,708.1	23.2	
Selling, general and administrative expenses	128.0	90.6	(37.4)	-41%	308.3	226.8	(81.5)	-36%
Other (income) expense net	(15.8)	(21.4)	(5.6)	-26%	23.6	(1.3)	(24.9)	NM
General corporate expenses	35.0	42.8	7.8	+18%	99.3	106.3	7.0	+7%
Securities litigation settlement and related costs	3.4		(3.4)	NM	165.3		(165.3)	NM
Total costs and expenses	2,973.0	2,938.2			8,281.4	8,039.9		
Operating income	327.0	144.1			761.2	867.6		
Interest accrued net	(157.9)	(164.2)	6.3	+4%	(495.2)	(491.0)	(4.2)	-1%
Investing income	50.7	31.1	19.6	+63%	140.9	44.9	96.0	NM
Early debt retirement costs					(31.4)		(31.4)	NM
Minority interest in income of consolidated subsidiaries	(12.1)	(6.8)	(5.3)	-78%	(27.5)	(16.8)	(10.7)	-64%
Other income (expense) net	2.8	(1.1)	3.9	NM	18.9	12.5	6.4	+51%
Income from continuing operations before income taxes	210.5	3.1			366.9	417.2		
	100.4	(2.6)	(103.0)	NM	189.6	168.6	(21.0)	-12%

Provision (benefit) for income taxes								
Income from continuing operations	110.1	5.7			177.3	248.6		
Loss from discontinued operations	(3.9)	(1.3)	(2.6)	-200%	(15.2)	(1.8)	(13.4)	NM
Net income	$ 106.2	$ 4.4			$ 162.1	$ 246.8		

* + = Favorable Change; = Unfavorable Change; NM = A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Three months ended September 30, 2006 vs. three months ended September 30, 2005

The increase in *revenues* is largely due to increased crude marketing revenues, increased natural gas liquid (NGL) volumes and prices, increased olefins revenues, and increased NGL marketing revenues at Midstream. Additionally, Exploration & Production revenues increased primarily due to increased production. Partially offsetting these increases are decreased realized revenues at Power associated with decreased power sales volumes and lower natural gas sales prices.

The increase in *costs and operating expenses* is primarily due to increased crude marketing costs, higher olefins production costs and increased NGL marketing purchases at Midstream. Additionally, Exploration & Production s costs increased primarily due to increased depreciation, depletion and amortization expense associated with higher production and increased capitalized drilling costs. Offsetting these increases is a decrease in Power s costs primarily due to a decrease in power purchase volumes and lower natural gas purchase prices.

The increase in *SG&A* is largely due to increased personnel costs, insurance expense and information systems support costs at our Gas Pipeline segment.

Other (income) expense net, within *operating income* in third-quarter 2006 includes:

Income of $12.7 million due to reducing contingent obligations associated with our former distributive power generation business at Power;

Gains on sales of assets of $7.9 million at Midstream.

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Management s Discussion and Analysis (Continued)

Other (income) expense net, within *operating income*, in third-quarter 2005 includes a $21.7 million gain on the sale of certain natural gas properties at Exploration & Production.

General corporate expenses decreased primarily due to the absence of $13.8 million of insurance settlement charges in 2005 associated with certain insurance coverage allocation issues.

The decrease in *interest accrued net* is largely due to both an increase in capitalized interest due to increased capital projects and a reduction in interest expense associated with an overall reduction in our average debt balance.

The increase in *investing income* is due to increased equity earnings of $12.3 million due largely to the absence of equity losses in 2006 on our fully impaired Longhorn investment. The remaining increase is largely due to increased earnings on cash and cash equivalent balances mainly due to higher interest rates and increased earnings on margin deposits.

Provision for income taxes was unfavorable due primarily to higher pre-tax income in 2006 as compared to 2005. 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 benefit for the three months ended September 30, 2005, is less than the federal statutory rate due primarily to the effect of income tax settlements that resulted in a reduction of an accrual for income tax contingencies and taxes on foreign operations. Partially offsetting these variances are state income taxes and an increase in the valuation allowance.

Loss from discontinued operations includes a $3.7 million net-of-tax charge associated with a claim settlement related to a former exploration business.

Nine months ended September 30, 2006 vs. nine months ended September 30, 2005

The increase in *revenues* is largely due to increased crude marketing revenues, higher NGL revenues due to higher prices, increased NGL marketing revenues, and higher olefins revenues at our Midstream segment. Also, our Exploration & Production segment reported higher production revenues. Offsetting these increases are reduced Power revenues due to decreased power sales volumes.

The decrease in *costs and operating expenses* is largely due to reduced power purchase volumes at our Power segment. Offsetting this decrease are increases at Midstream due to increased crude marketing costs and increased NGL and olefins marketing costs. Also, our Exploration & Production segment reported higher depreciation, depletion and amortization associated with higher production and increased capitalized drilling costs.

The increase in *SG&A* is primarily due to increased personnel costs, insurance expense, higher information systems support costs and the absence of a $17.1 million reduction of pension expense at our Gas Pipeline segment in 2005. Additionally, our Exploration & Production segment experienced higher costs due to increased staffing in support of increased drilling and operational activity. Offsetting these increases is a $24.8 million gain at Power from the sale of certain Enron receivables to a third party.

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

- A $70.4 million accrual for a Gulf Liquids litigation contingency (see Note 11 of Notes to Consolidated Financial Statements);
- Losses on asset retirements of $5.2 million at Midstream primarily due to the impact of accelerating the timing of abandonment;
- Income of $12.7 million due to reducing contingent obligations associated with our former distributive power generation business at Power;
- Income of $9 million due to a settlement of an international contract dispute at Midstream;
- Gains on sales of properties of $7.9 million at Midstream;
- Gains on foreign currency exchanges at Power of approximately $5 million;

Management s Discussion and Analysis (Continued)

- An approximate $4 million gain on sale of idle gas treating equipment at Midstream;
- Income of $2 million associated with the reversal of an accrued litigation contingency due to a favorable court ruling at Gas Pipeline.

Other (income) expense net within *operating income* in 2005 includes:

- A $13.5 million accrual for litigation contingencies at Power;
- A $4.6 million accrual for a regulatory settlement at Power;
- Gains of $29.6 million associated with the sale of certain natural gas properties at Exploration and Production;
- A $4 million write-off of project costs in our Other segment.

General corporate expenses decreased primarily due to the absence of $13.8 million of insurance settlement charges in 2005 associated with certain insurance coverage allocation issues.

The *securities litigation settlement and related costs* is the result of an agreement-in-principle to settle class-action securities litigation filed on behalf of purchasers of our securities between July 24, 2000 and July 22, 2002.

The increase in *interest accrued net* is due to $20.6 in interest expense associated with our Gulf Liquids litigation contingency, offset by lower interest expense associated with reduced debt balances and increased capitalized interest due to increased capital projects.

The increase in *investing income* is due to:

- The absence of a $49.1 million impairment in 2005 on our investment in Longhorn;
- A $31.8 million increase in interest income primarily associated with increased earnings on cash and cash equivalent balances mainly due to increased interest rates and higher earnings on margin deposits;
- Increased equity earnings of $30.1 million due largely to the absence of equity losses in 2006 on Longhorn and increased earnings of our Discovery investment;

These increases are partially offset by the absence of the $8.6 million gain on sale of our remaining MAPL and Seminole investments at Midstream in 2005.

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 (see Notes 9 and 10 of Notes to Consolidated Financial Statements).

Provision for income taxes was unfavorable due primarily to the effect of taxes on foreign operations, nondeductible expenses associated with the conversion of convertible debentures and estimated nondeductible expenses associated with securities litigation. This unfavorable variance was partially offset by lower pre-tax income in 2006 as compared to 2005. 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, nondeductible expenses associated with the conversion of convertible debentures and estimated nondeductible expenses associated with securities litigation. The effective income tax rate for the nine months ended September 30, 2005 is greater than the federal statutory rate due primarily to the effect of state income taxes, an increase in the valuation allowance and nondeductible expenses. Partially offsetting these variances are income tax settlement that resulted in a reduction of an accrual for income tax contingencies and taxes on foreign operations.

Loss from discontinued operations includes an $11.9 million net-of-tax arbitration charge related to our former chemical fertilizer business and a $3.7 million net-of-tax charge associated with a claim settlement related to a former exploration business.

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Management s Discussion and Analysis (Continued)

Results of Operations Segments

Exploration & Production

Overview of Nine Months Ended September 30, 2006

In the first nine months of 2006, we continued our strategy to rapidly expand the development of our drilling inventory. Accordingly, we:

- Increased average daily domestic production levels by approximately 21 percent compared to the first nine months of 2005. The average daily domestic production for the first nine months was approximately 727 million cubic feet of gas equivalent (MMcfe) in 2006 compared to 601 MMcfe in 2005. The increased production is primarily due to increased development within the Piceance and Powder River basins, which is a result of our accelerated growth plan for 2006.

- Increased our development drilling program by 12 percent, surpassing drilling activities during the first nine months of 2005. We drilled 1,348 gross wells in the first nine months of 2006 compared to 1,208 in 2005. Capital expenditures for domestic drilling, development, and acquisition activity in the first nine months of 2006 were approximately $965 million compared to approximately $542 million in 2005.

For the first nine months of 2006, the benefits of higher production volumes were partially offset by increased operating costs. The increase in operating costs was primarily due to higher well service and industry costs, increased overall production volumes, and production enhancement workover activities.

Significant events

Through October 2006, eight new state-of-the-art FlexRig4® drilling rigs have been placed into service pursuant to our lease agreement with Helmerich & Payne. The March 2005 contract provides for the operation of ten new drilling rigs, each for a primary lease term of three years. This arrangement supports our plan to accelerate the pace of natural gas development in the Piceance basin through both deployment of the additional rigs and also through the drilling and operational efficiencies of the new rigs.

In the first nine months of 2006, we substantially increased our position in the Fort Worth basin by acquiring various producing properties and undeveloped leasehold interests for approximately $64 million. These acquisitions increase our diversification into the Mid-Continent region and allow us to use our horizontal drilling expertise to develop wells in the Barnett Shale formation.

In September 2006, we acquired additional acreage along with the associated leasehold interest in the Paradox basin for approximately $12 million. This acreage is located within several counties in northwest Colorado.

In the first nine months of 2006, we entered into various derivative collar agreements at the basin level which, in the aggregate, hedge an additional 155 MMcfe per day for production in 2007 and 105 MMcfe per day for production in 2008.

Outlook for the Remainder of 2006

Our expectations for the remainder of the year include:

- Continuing our accelerated 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 $250 and $300 million.

- Deploying the remaining two contracted FlexRig4® drilling rigs dedicated specifically to drilling activity in the Piceance basin.

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Management s Discussion and Analysis (Continued)

Continue to grow our average daily domestic production level goal of 15 to 20 percent growth compared to 2005 for the remainder of 2006.

Approximately 288 MMcfe of our forecasted 2006 daily production is hedged by NYMEX and basis fixed price contracts at prices that average $3.89 per Mcfe at a basin level. In addition, we have collar agreements totaling 64 MMcfe per day at a weighted average floor price of $6.62 per Mcfe and a weighted average ceiling price of $8.42 per Mcfe and a basin (Northwest Pipeline/Rockies) collar agreement for 50 MMcfe per day at a floor price of $6.05 per Mcfe and a ceiling price of $7.90 per Mcfe.

The main risk to achieving our expectations is fourth-quarter 2006 weather conditions at certain of our locations.

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2006	**2005**	**2006**	**2005**
	(Millions)		(Millions)	
Segment revenues	$ 371.1	$ 318.4	$ 1,069.4	$ 848.9
Segment profit	$ 144.5	$ 158.8	$ 411.9	$ 380.8

Three months ended September 30, 2006 vs. three months ended September 30, 2005

Total *segment revenues* increased $52.7 million, or 17 percent, primarily due to the following:

$33 million, or 12 percent, increase in domestic production revenues reflecting $68 million associated with a 24 percent increase in production volumes sold, offset by $35 million associated with a 10 percent decrease in net realized average prices. The increase in production volumes was primarily from the Piceance, Powder River, and Fort Worth basins. The lower net realized average prices reflect the downward trend of average market prices for natural gas in the third quarter of 2006 compared to 2005.

$5 million unrealized gain from hedge ineffectiveness and forward mark-to-market losses on certain basis swaps not designated as hedges in the third quarter of 2006 and the absence of a $16 million unrealized loss from hedge ineffectiveness attributable to our NYMEX collars in the third quarter of 2005.

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 39 percent of domestic production in the third quarter of 2006 was hedged by NYMEX and basis fixed price contracts at a weighted average price of $3.80 per Mcfe at a basin level compared to 45 percent hedged at a weighted average price of $3.96 per Mcfe for the same period in 2005. In addition, approximately 15 percent of domestic production was hedged in the following collar agreements in the third quarter of 2006:

NYMEX collar agreement for approximately 49 MMcfe per day at a floor price of $6.50 per Mcfe and a ceiling price of $8.25 per Mcfe.

NYMEX collar agreement for approximately 15 MMcfe per day at a floor price of $7.00 per Mcfe and a ceiling price of $9.00 per Mcfe.

Northwest Pipeline/Rockies collar agreement for approximately 50 MMcfe per day at a floor price of $6.05 per Mcfe and a ceiling price of $7.90 per Mcfe at a basin level.

In the third quarter of 2005, approximately 8 percent of domestic production was hedged in a NYMEX collar agreement for approximately 50 MMcfe per day at a floor price of $6.75 per Mcfe and a ceiling price of $8.50 per Mcfe.

Our hedges are executed with our Power segment which, in turn, executes offsetting derivative contracts with unrelated third parties. Generally, Power bears the counterparty performance risks associated with unrelated third

Management s Discussion and Analysis (Continued)
parties. Hedging decisions are made considering our overall commodity risk exposure and are not executed independently by Exploration & Production.

Total costs and expenses increased $67 million, primarily due to the following:

$29 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs.

$11 million higher lease operating expense primarily due to the increased number of producing wells, higher well service and industry costs, and increased production enhancement workover activities and increased activity in our new Fort Worth basin.

$8 million higher selling, general and administrative expenses primarily due to increased staffing in support of increased drilling and operational activity including higher compensation. In addition, we incurred higher legal, insurance, and information technology support costs also related to the increased activity.

The absence in 2006 of a $21.7 million gain on the sale of properties in 2005.

The $14.3 million decrease in s*egment profit* is primarily due to the absence in 2006 of the gain on the sale of properties in 2005, an approximately 10 percent decrease in net domestic average realized prices, and increased cost and expenses as previously discussed. Partially offsetting these decreases are substantially increased production volumes and higher income from hedge ineffectiveness.

Nine months ended September 30, 2006 vs. nine months ended September 30, 2005

Total *segment revenues* increased $220.5 million, or 26 percent, primarily due to the following:

$163 million, or 22 percent, increase in domestic production revenues reflecting $153 million primarily associated with a 21 percent increase in production volumes sold. The increase in production volumes was primarily from the Piceance, Powder River, and Fort Worth basins.

$9 million increase in production revenues from our international operations due to increased production volumes and higher average prices.

$21 million unrealized gain from hedge ineffectiveness and forward mark-to-market gains on certain basis swaps not designated as hedges and the absence of a $16 million unrealized loss from hedge ineffectiveness attributable to our NYMEX collars in 2005.

Total costs and expenses increased $193 million, primarily due to the following:

$68 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs.

$37 million higher lease operating expense primarily due to the increased number of producing wells, higher well service and industry costs, and increased production enhancement workover activities and approximately $3 million of lease operating expense related to 2005.

$19 million higher operating taxes primarily due to higher production volumes sold.

$23 million higher selling, general and administrative expenses primarily due to increased staffing in support of increased drilling and operational activity including higher compensation. In addition, we incurred higher legal, insurance, and information technology support costs also related to the increased activity.

The absence in 2006 of $29.6 million of gains on the sales of properties in 2005.

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Management s Discussion and Analysis (Continued)

The $31.1 million increase in *segment profit* is primarily due to higher production volumes and increased income from hedge ineffectiveness, partially offset by higher costs and expenses as discussed previously, and the absence in 2006 of $29.6 million of gains on the sales of properties in 2005. *Segment profit* also includes a $10 million increase in our international operations reflecting higher revenue and equity earnings primarily due to a 20 percent increase in net realized average oil and gas prices from our Apco Argentina operations.

Gas Pipeline

Overview of Nine Months Ended September 30, 2006

Gulfstream

In March 2006, our equity method investee, Gulfstream, announced a new long-term agreement with a Florida utility company, which fully subscribed the pipeline s mainline capacity on a long-term basis. Under the agreement, Gulfstream will extend its existing pipeline approximately 35 miles within Florida. The agreement is subject to the approval of various authorities. Construction of the extension is anticipated to begin in early 2008 with a targeted completion of summer 2008.

In May 2006, Gulfstream announced a new agreement to provide 155,000 Dth/d of natural gas to a Florida utility. As a result, Gulfstream will increase its mainline capacity by adding approximately 17.5 miles of pipeline in Florida. Construction of the additional mainline capacity is anticipated to begin in January 2008.

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 450,000 Dth/d through the 30-inch diameter line and is estimated to cost $64 million. The expansion is expected to be in service by January 2007.

Leidy to Long Island expansion project

In May 2006, we received FERC approval to expand Transco s natural gas pipeline in the northeast United States. The estimated cost of the project is approximately $127 million with three-quarters of that spending expected to occur in 2007. The expansion will provide 100,000 Dth/d of incremental firm capacity and is expected to be in service by November 2007.

Potomac expansion project

In July 2006, we filed an application with the FERC to expand Transco s existing facilities in the Mid-Atlantic region of the United States by constructing 16.5 miles of 42-inch pipeline. The project will provide 165,000 Dth/d of incremental firm capacity. The estimated cost of the project is approximately $74 million, with an anticipated in-service date of November 2007.

Grays Harbor

Effective January 2005, Duke Energy Trading and Marketing, LLC (Duke) terminated its firm transportation agreement related to Northwest Pipeline s Grays Harbor lateral. In January 2005, Duke paid Northwest Pipeline $94 million for the remaining book value of the asset and the related income taxes. We and Duke have not agreed on the amount of the income taxes due Northwest Pipeline as a result of the contract termination. We have deferred the $6 million difference between the proceeds and net book value of the lateral pending resolution of the disputed early termination obligation.

On June 16, 2005, we filed a Petition for a Declaratory Order with the FERC requesting that it rule on our interpretation of our tariff to aid in resolving the dispute with Duke. On July 15, 2005, Duke filed a motion to intervene and provided comments supporting its position concerning the issues in dispute.

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Management s Discussion and Analysis (Continued)

On October 4, 2006, the FERC issued its Order on Petition for Declaratory Order, providing clarification on issues relating to Duke s obligation to reimburse us for future tax expenses. We are reviewing the Order and anticipate filing a request for rehearing. Based upon the order, as written, we do not anticipate any adverse impact to our results of operations or financial position.

Outlook for the Remainder of 2006

Filing of rate cases

Northwest Pipeline and Transco have each filed a general rate case with the FERC during 2006. The new transportation and storage rates for both pipelines will be effective, subject to refund, in the first quarter of 2007.

Northwest Pipeline capacity replacement project

In September 2005, we received FERC approval to construct and operate approximately 80 miles of 36-inch pipeline loop as a replacement for most of the capacity previously served by 268 miles of 26-inch pipeline in the Washington state area. As of November 1, 2006, construction is substantially complete. By December 2006, all of the facilities are expected to be in service and the abandonment of the 26-inch pipeline is expected to be completed. The estimated cost of the project is $333 million.

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(Millions)		(Millions)	
Segment revenues	$ 334.2	$ 345.8	$ 1,005.5	$ 1,038.1
Segment profit	$ 109.0	$ 161.1	$ 366.4	$ 493.0

Three months ended September 30, 2006 vs. three months ended September 30, 2005

Revenues decreased $11.6 million, or 3 percent, due primarily to $14 million lower revenues associated with exchange imbalance settlements (offset in *costs and operating expenses*).

Costs and operating expenses increased $15 million, or 8 percent, due primarily to the absence of $14.2 million of income in 2005 associated with the resolution of litigation. Additional increases include $7 million of higher contract and outside service costs due primarily to higher pipeline assessment and repair costs, a $3 million increase in depreciation expense due to property additions and $2 million higher operating taxes. Partially offsetting these increases are $14 million of lower costs associated with exchange imbalance settlements (offset in *revenues*).

SG&A expenses increased $22 million, or 91 percent, due primarily to $6 million higher personnel costs, $5 million higher information systems support costs and $4 million higher property insurance expenses.

The $52.1 million or 32 percent decrease in *segment profit* is due primarily to the increases in *costs and operating expenses* and *SG&A expenses* as previously discussed and $8 million lower equity earnings due largely to our investments in Gulfstream and Pacific Connector.

Nine months ended September 30, 2006 vs. nine months ended September 30, 2005

Revenues decreased $32.6 million, or 3 percent, due primarily to $35 million lower revenues associated with exchange imbalance settlements (offset in *costs and operating expenses*).

Costs and operating expenses increased $31 million, or 6 percent, due to a $10 million increase in depreciation expense due to property additions, the absence of $14.2 million of income in 2005 associated with the resolution of litigation, and the absence of $12.1 million of expense reductions during 2005 related to the carrying value of certain liabilities. The increase is also due to $13 million higher contract and outside service costs due primarily to higher pipeline assessment and repair costs, $7 million higher operating taxes and $5 million higher materials and supplies expenses. Partially offsetting these increases are $35 million of lower costs associated with exchange imbalance settlements (offset in *revenues*).

SG&A expenses increased $63 million, or 128 percent, due primarily to the absence of a 2005 $17.1 million reduction in pension costs to correct an error in prior periods, $17 million higher personnel costs, $12 million higher information systems support costs, $7 million higher property insurance expenses and the absence of $5.6 million of cost reductions in 2005 that related to correcting the carrying value of certain liabilities.

Management s Discussion and Analysis (Continued)

Our management concluded that the effects of the corrections discussed in the two previous paragraphs were not material to our consolidated results for 2005 or prior periods, or to our trend of earnings.

The $126.6 million or 26 percent decrease in *segment profit* is due primarily to the increases in *costs and operating expenses* and *SG&A expenses* as previously discussed and the absence of a $4.6 million construction completion fee recognized in 2005 related to our investment in Gulfstream.

Midstream Gas & Liquids

Overview of Nine Months Ended September 30, 2006

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 volumes to our assets by providing highly reliable service to our customers.

Williams Partners L.P. acquired a 25.1 percent interest in Four Corners gathering and processing business

In June 2006, Williams Partners L.P. completed its acquisition of 25.1 percent of our interest in Williams Four Corners LLC for $360 million. The acquisition was completed after successfully closing a $150 million private debt offering of senior unsecured notes due 2011 and an equity offering of approximately $225 million in net proceeds. The debt and equity issued by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively. Williams Four Corners LLC owns certain gathering, processing and treating assets in the San Juan Basin in Colorado and New Mexico.

Gulf Coast operations return to normal after 2005 s hurricanes

In 2005, Hurricanes Dennis, Katrina and Rita caused temporary shut-downs of most of our facilities and our producers facilities in the Gulf Coast region, which reduced product flows in the second half of 2005. Our major facilities resumed normal operations shortly after the passage of each hurricane except for our Devils Tower spar which returned to service in early November 2005 and our Cameron Meadows gas processing plant which returned to partial service in February 2006 and full service in early November 2006. While some smaller production areas remain at below-normal levels, overall product flows returned to pre-hurricane levels during the first quarter of 2006.

Expansion efforts in growth areas

Consistent with our strategy, we continued to expand our operations where we have large scale assets in growth basins. The production volumes serviced from the Triton and Goldfinger fields located in the deepwater Gulf of Mexico resulted in $34 million in incremental revenues to our Devils Tower facilities during the first nine months of 2006. We continued construction on a 37-mile extension of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect located in Mississippi Canyon. This extension, estimated to cost $177 million, is expected to be ready for service by the third quarter of 2007. Also, we continued construction at our existing gas processing plant located near Opal, Wyoming, to add a fifth cryogenic train capable of processing up to 350 MMcf/d. This plant expansion is expected to be in service by the first quarter of 2007 to begin processing gas from the Pinedale Anticline field.

In May 2006, we entered into an agreement to develop new pipeline capacity for transporting natural gas liquids from production areas in southwestern Wyoming to central Kansas. The other party to the agreement reimbursed us for the development costs we incurred to date for the proposed pipeline and initially will own 99 percent of the pipeline, known as Overland Pass Pipeline Company, LLC. We retained a 1 percent interest and have the option to increase our ownership to 50 percent and become the operator within two years of the pipeline becoming operational. Start-up is planned for early 2008. Additionally, we have agreed to dedicate our equity NGL volumes from our two Wyoming plants for transport under a long-term shipping agreement. The terms represent significant savings compared with the existing tariff and other alternatives considered. The exiting pipeline transporter has filed for increased tariffs which would increase transportation costs until this pipeline is in service.

Favorable commodity price margins

The actual realized NGL per unit margins at our processing plants exceeded Midstream s rolling five-year average for the last five quarters. Previously we compared the actual realized NGL per unit margins to the historical average for the calendar years 2001 through 2005. Due to recent higher NGL margins, we have begun to

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Management s Discussion and Analysis (Continued)

compare actual realized NGL per unit margins to a rolling five-year average ending September 30, 2006. The actual realized NGL per unit margins at our processing plants exceeded Midstream s five-year average of calendar years 2001 through 2005 for the last nine quarters. The geographic diversification of Midstream assets contributed significantly to our actual realized unit margins exceeding the industry benchmark at Mont Belvieu for gas processing spreads. The largest impact was realized at our western United States gas processing plants, which benefited from lower regional market natural gas prices. In the first nine months of 2006, NGL production rebounded from levels experienced in fourth-quarter 2005 in response to improved gas processing spreads as crude prices averaged nearly $70 per barrel and natural gas prices decreased.

Domestic Gathering and Processing Net Per Unit NGL Margin with Production and Sales Volumes by Quarter

Gulf Liquids litigation

We recorded a pre-tax charge of $91 million resulting from jury verdicts in civil litigation (see Note 11 of Notes to the Consolidated Financial Statements). The $91 million charge reflects our estimated exposure for actual damages of $70.4 million, including estimated legal fees of $2.4 million, and potential pre-judgment interest of $20.6 million. Midstream Other segment profit reflects the $70.4 million charge for the estimated actual damages and legal fees. The matter is related to a contractual dispute surrounding construction in 2000 and 2001 of certain refinery off-gas processing facilities by Gulf Liquids. In addition, it is reasonably possible that any ultimate judgment may include additional amounts of $185 million in excess of our accrual, which represents our estimate of potential punitive damage exposure under Texas law. The jury verdicts are subject to trial and appellate court review. Entry of a judgment in the trial court is expected in the first quarter of 2007. If the trial court enters a judgment consistent with the jury s verdicts against us, we will seek a reversal through appeal.

Outlook for the Remainder of 2006

The following factors could impact our business in the remainder of 2006 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 five quarters were above our rolling five-year average. We expect unit margins in fourth-quarter 2006 to continue to exceed 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. As part of our efforts to manage commodity price risks on an enterprise basis, we initiated the use of commodity hedging strategies. As of September 30, 2006, we have executed swap agreements and forward sales contracts for approximately 40 percent of our October 2006 domestic NGL sales volumes or approximately 1.2 million barrels.

Gathering and processing revenues at our facilities are expected to be at or above levels of the prior year due to continued strong drilling activities in our core basins. 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.

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Management s Discussion and Analysis (Continued)

We expect processing volumes to increase as the fifth cryogenic train at Opal is placed into service and Cameron Meadows returns to service.

We will continue to invest in facilities in the growth basins in which we provide services. The latest expansion of our Wamsutter gathering system became operational late in the second quarter of 2006 as scheduled and contributed approximately $1 million in incremental fee revenues during the third quarter.

Margins in our olefins unit are highly dependent upon continued economic growth within the U.S. and any significant slow down in the economy would reduce the demand for the petrochemical products we produce in both Canada and the U.S.

The per unit rate of revenue recognition for resident production at our Devils Tower facility increased as a result of a reserve study that was completed during the first quarter of 2006. While this change impacts revenues, it does not impact the cash flows from the resident production.

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

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.

As previously announced, we continue to have a goal of completing additional transactions of approximately $1.0 billion to $1.5 billion involving gathering and processing assets between us and Williams Partners L.P., our master limited partnership, within the next three months.

We are currently negotiating with our customer in Venezuela to resolve approximately $14 million in past due invoices 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 a disproportionate escalation over time. We believe the receivables, net of associated reserves, are fully collectible. Although we believe our negotiations will be successful, failure to resolve this matter could ultimately trigger noncompliance default provisions in the services agreement.

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(Millions)		(Millions)	
Segment revenues	$ 1,117.0	$ 754.7	$ 3,139.9	$ 2,341.8
Segment profit				
Domestic gathering & processing	$ 181.3	90.4	475.9	289.1
Venezuela	22.5	25.8	80.0	72.0
Other	29.2	18.6	(11.5)	40.9
Unallocated general and administrative expense	(20.8)	(13.7)	(50.0)	(43.2)
Total	$ 212.2	$ 121.1	$ 494.4	$ 358.8

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 *unallocated 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, 2006 vs. three months ended September 30, 2005

The $362.3 million increase in Midstream s *revenues* is largely due to:

A $194 million increase in crude marketing revenues, which is offset by a similar change in costs, resulting from additional deepwater production coming on-line in November 2005;

Management s Discussion and Analysis (Continued)

- A $71 million increase in revenues associated with production of NGLs, due to $46 million in higher NGL volumes and $25 million in higher prices;
- A $55 million increase in revenues in our olefins unit due to higher prices combined with higher volumes;
- A $48 million increase in the marketing of NGLs and olefins, which is offset by a similar change in costs, resulting from higher volumes;
- A $16 million increase in fee revenues resulting primarily from higher deepwater production handling volumes and higher per unit rates as a result of the reserve study that was completed during the first quarter of 2006;
- A $19 million reduction in NGL revenues due to a change in classification of NGL transportation and fractionation expenses from costs of goods sold to net revenues (offset in costs and operating expenses).

Costs and operating expenses increased $271 million primarily as a result of:

- A $194 million increase in crude marketing purchases, which is offset by a similar change in revenues;
- A $48 million increase in NGL and olefins marketing purchases, which is offset by a similar change in revenues;
- A $39 million increase in costs associated with production in our olefins unit;
- A $19 million increase in operating expenses including a $10.6 million accounts payable accrual adjustment, higher insurance expense, personnel and related benefit expenses and system losses;
- A $19 million reduction in NGL transportation and fractionation expenses due to the above-noted change in classification (offset in revenues);
- A $14 million decrease in costs associated with the production of NGLs due to $47 million in lower natural gas prices offset by $33 million in higher natural gas purchase volumes.

The $91.1 million increase in Midstream *segment profit* is primarily due to higher net NGL margins, higher deepwater production handling volumes, higher margins in our olefins unit, gains on the sales of assets, higher gathering revenues and higher equity earnings in our equity investment in Discovery Producer Services, L.L.C., partially offset by higher operating costs, lower marketing margins and losses related to the retirement of assets. A more detailed analysis of the *segment profit* of Midstream s various operations is presented as follows.

<u>Domestic gathering & processing</u>

The $90.9 million increase in *domestic gathering and processing segment profit* includes a $43 million increase in the West region and a $48 million increase in the Gulf Coast region.

The $43 million increase in our West region s *segment profit* primarily results from higher net product margins and gathering rates, partially offset by higher operating expenses. The specific components of this net increase include the following:

- Net NGL margins increased $49 million compared to the third quarter of 2005. This increase was driven by a significant increase in average per unit NGL margins combined with slightly higher volumes.
- Gathering and processing revenues are $7 million higher due primarily to higher gathering rates, incremental revenues associated with the Wamsutter expansion, and higher processing volumes. Gathering fees are higher as a result of an increase in our fee revenues due to higher average per-unit gathering rates, which more than offset the small decline in volumes. Processing volumes are higher due to customers electing to take liquids and pay processing fees.

Management s Discussion and Analysis (Continued)

Operating expenses are $15 million higher including a $7 million accounts payable accrual adjustment, $3 million in higher net system product losses as a result of the settlement of a measurement adjustment claim and higher personnel and related benefit expenses.

The $48 million increase in the Gulf Coast region s *segment profit* is primarily a result of higher net NGL margins, higher volumes from our deepwater facilities and gains on the sales of assets, partially offset by higher operating expenses and losses associated with the retirement of assets. The significant components of this increase include the following:

Net NGL margins increased $36 million compared to the third quarter of 2005. This increase was driven by a significant increase in average per unit NGL margins combined with significantly higher volumes.

Fee revenues from our deepwater assets increased $16 million as a result of $15 million in higher volumes flowing across the Devils Tower facility and $5 million in higher Devils Tower unit-of-production rates recognized as a result of a new reserve study. These increases are partially offset by a $4 million decline in other gathering and production handling revenues due primarily to volume declines in other areas.

Gains on the sales of assets of $7.9 million due to the sale of certain gathering assets and a processing plant in July 2006.

Operating expenses are $5 million higher due primarily to $4 million in higher insurance costs and a $1 million accounts payable accrual adjustment.

Losses on asset retirements of $5.2 million, primarily due to the impact of accelerating the timing of abandonment.

<u>Venezuela</u>

Segment profit for our Venezuela assets decreased $3.3 million primarily resulting from lower equity earnings of our Accroven investment due to higher foreign income taxes.

<u>Other</u>

The $10.6 million increase in *segment profit* of our other operations is primarily the result of $16 million higher margins from our olefins unit due primarily to higher prices and $6 million higher equity earnings of our equity investment in Discovery Producer Services, L.L.C., due to higher NGL volumes and higher processing volumes, partially offset by a $6 million decrease in margins resulting from the marketing of olefins and an $8 million decrease in margins resulting from the marketing of NGLs due to the impact of commodity prices on sales of NGL pipeline inventories in transit. NGL prices overall declined during the third quarter of 2006 as compared to increasing during the third quarter of 2005.

<u>Unallocated general and administrative expense</u>

The $7.1 million increase in expense is primarily due to higher personnel and related benefit expenses.

Nine months ended September 30, 2006 vs. nine months ended September 30, 2005

The $798.1 million increase in Midstream s *revenues* is largely due to:

A $495 million increase in crude marketing revenues, which is offset by a similar change in costs, resulting from additional deepwater production coming on-line in November 2005;

A $144 million increase in revenues associated with the production of NGLs, primarily due to higher NGL prices combined with higher volumes;

An $87 million increase in the marketing of NGLs and olefins, which is offset by a similar change in costs, resulting from higher prices;

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Management s Discussion and Analysis (Continued)

- A $74 million increase in revenues in our olefins unit due to higher prices;
- A $73 million increase in fee-based revenues including $49 million in higher production handling volumes;
- A $68 million reduction in NGL revenues due to a change in classification of NGL transportation and fractionation expenses from costs of goods sold to net revenues (offset in costs and operating expenses).

Costs and operating expenses increased $615 million primarily as a result of:

- A $495 million increase in crude marketing purchases, which is offset by a similar change in revenues;
- An $87 million increase in NGL and olefins marketing purchases, offset by a similar change in revenues;
- A $57 million increase in costs associated with production in our olefins unit;
- A $52 million increase in operating expenses including a $10.6 million accounts payable accrual adjustment, higher system losses, insurance expense, personnel and related benefit expenses, and depreciation;
- A $68 million reduction in NGL transportation and fractionation expenses due to the above-noted change in classification (offset in revenues);
- A $20 million decrease in plant fuel and costs associated with the production of NGLs due primarily to lower gas prices.

The $135.6 million increase in Midstream *segment profit* is primarily due to higher net NGL margins, higher deepwater production handling revenues, higher gathering and processing revenues, higher margins from our olefins unit, settlement of an international contract dispute and gains on the sale of assets, largely offset by the $70.4 million charge related to the Gulf Liquids litigation contingency combined with higher operating costs and losses on the retirement of assets. A more detailed analysis of the *segment profit* of Midstream s various operations is presented as follows.

Domestic gathering & processing

The $186.8 million increase in *domestic gathering and processing segment profit* includes an $87 million increase in the West region and a $100 million increase in the Gulf Coast region.

The $87 million increase in our West region s *segment profit* primarily results from higher net product margins and higher gathering and processing revenues, partially offset by higher operating expenses. The significant components of this increase include the following:

- Net NGL margins increased $99 million compared to 2005. This increase was driven by a significant increase in average per unit NGL margins offset by a small decrease in volumes.
- Net revenues from our gathering and processing business increased $16 million. Gathering fees are higher as a result of an increase in our fee revenues due to higher average per-unit gathering rates, which more than offset the small decline in volumes related to natural depletion of coal seam wells. Processing volumes are higher due to customers electing to take liquids and pay processing fees.
- A gain on sale of idle gas treating equipment of approximately $4 million during first quarter 2006.
- Operating expenses increased $36 million including a $7 million accounts payable accrual adjustment; $5 million in higher personnel and related benefit expenses; a $4 million increase in maintenance projects; $3 million in higher gathering fuel costs; $3 million in higher leased compression costs; $3 million in turbine overhaul costs; $2 million in higher net system product losses as a result of higher loss volumes coupled with higher gas prices in the first quarter of 2006 and the settlement of a measurement adjustment claim in the third

quarter of 2006; a $2 million increase in materials and supplies; and $2 million in higher depreciation.

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Management s Discussion and Analysis (Continued)

The $100 million increase in the Gulf Coast region s *segment profit* is primarily a result of higher net NGL margins, higher volumes from our deepwater facilities and a gain on the sale of assets, partially offset by higher operating expenses and a loss on the retirement of assets. The significant components of this increase include the following:

Net NGL margins increased $65 million compared to the first nine months of 2005. This increase was driven by a significant increase in average per unit NGL margins combined with an increase in volumes.

Fee revenues from our deepwater assets increased $49 million as a result of $44 million in higher volumes flowing across the Devils Tower facility and $16 million in higher Devils Tower unit-of-production rates recognized as a result of a new reserve study. These increases are partially offset by an $11 million decline in other gathering and production handling revenues due to volume declines in other areas.

Gains on the sales of assets of $7.9 million due to the sale of certain gathering assets and a processing plant in July 2006.

Operating expenses increased $12 million primarily as a result of $7 million in higher insurance costs, $3 million in higher depreciation expense on our deepwater assets, and a $1 million accounts payable accrual adjustment.

Losses on asset retirements of $5.2 million, primarily due to the impact of accelerating the timing of abandonment.

Venezuela

Segment profit for our Venezuela assets increased $8.0 million and includes $9 million resulting from a settlement of a contract dispute and $3 million in higher revenues due to higher natural gas volumes and prices at our compression facility. These were partially offset by $2 million in higher expenses related to service agreements for turbine maintenance and the timing of other planned maintenance costs and $2 million lower equity earnings primarily due to higher foreign income taxes.

Other

The $52.4 million decrease in *segment profit* of our other operations is largely due to the $70.4 million charge related to the Gulf Liquids litigation contingency combined with $9 million in lower margins related to the marketing of olefins and $7 million in lower margins related to significant increases in NGL prices during 2005 as compared to smaller overall increases in NGL prices during 2006. These were partially offset by $17 million in higher propane and propylene margins, $12 million in higher earnings from our equity investment in Discovery Producer Services, L.L.C., primarily as a result of higher fee-based revenues and higher NGL prices, $6 million in higher fractionation, storage and other fee revenues, and a $4 million favorable transportation settlement.

Unallocated general and administrative expense

The $6.8 million increase in expense is primarily due to higher personnel and related benefit expenses.

Power

Overview of Nine Months Ended September 30, 2006

Power s comparative operating results for the first nine months of 2006 reflect an accrual gross margin loss on its nonderivative tolling contracts and lower of cost or market adjustments on natural gas inventory. Power s results for the first nine months of 2006 were also influenced by a decrease in forward power prices against a net long derivative position, which caused net forward unrealized mark-to-market losses. The chart below illustrates the impact of the accrual gross margin loss and the unrealized mark-to-market loss on Power s total gross margin. The below chart does not reflect, however, cash flows that Power realized in the first nine months of 2006 from hedges for which mark-to-market gains or losses had been previously recognized.

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Management s Discussion and Analysis (Continued)

Power Year-to-Date Gross Margin

In the first nine months of 2006, Power continued to focus on its objectives of minimizing financial risk, maximizing cash flow, meeting contractual commitments, executing new contracts to hedge its portfolio and providing functions that support our natural gas businesses.

Key factors that may influence Power s financial condition and operating performance include:

- Prices of power and natural gas, including changes in the margin between power and natural gas prices;
- Changes in power and natural gas price volatility;
- Changes in power and natural gas supply and demand;
- Changes in the regulatory environment;
- The inability of counterparties to perform under contractual obligations due to their own credit constraints;
- Changes in interest rates;
- Changes in market liquidity, including changes in the ability to effectively hedge commodity price risk;
- The inability to apply hedge accounting.

Outlook for the Remainder of 2006

For the remainder of 2006, Power intends to service its customers needs while increasing the certainty of cash flows from its long-term tolling contracts by executing new long-term electricity and capacity sales contracts.

As Power continues to apply hedge accounting in 2006, its future earnings may be less volatile. However, not all of Power s derivative contracts qualify for hedge accounting. Because certain derivative contracts qualifying for hedge accounting were previously marked-to-market through earnings prior to their designation as cash flow hedges, the amounts recognized in future earnings under hedge accounting will not necessarily align with the expected cash flows to be realized from the settlement of those derivatives. For example, future earnings may reflect losses from underlying transactions, such as natural gas purchases and power sales associated with our tolling contracts, which have been hedged by derivatives. A portion of the offsetting gains from these hedges, however, has already been recognized in prior periods under mark-to-market accounting. So, while earnings in a reported period may not reflect the full amount realized from our hedges, cash flows do continue to reflect the total amount from both the hedged transactions and the hedges.

Management s Discussion and Analysis (Continued)

Even with the application of hedge accounting, Power s earnings will continue to reflect mark-to-market volatility from unrealized gains and losses resulting from:

- Market movements of commodity-based derivatives that represent economic hedges but which do not qualify for hedge accounting;
- Ineffectiveness of cash flow hedges, primarily caused by locational differences between the hedging derivative and the hedged item or changes in the creditworthiness of counterparties;
- Market movements of commodity-based derivatives that are held for trading purposes.

The fair value of Power s tolling, full requirements, transportation, storage and transmission contracts is not reflected in the balance sheet since these contracts are not derivatives. Some of these contracts have a significant negative estimated fair value and could result in future operating losses.

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(Millions)		(Millions)	
Realized revenues	$ 2,119.6	$ 2,384.0	$ 5,775.4	$ 6,205.1
Net forward unrealized mark-to-market gains (losses)	(15.5)	(141.1)	(11.1)	102.1
Segment revenues	2,104.1	2,242.9	5,764.3	6,307.2
Cost of sales	2,163.8	2,445.6	5,907.3	6,405.1
Gross margin	(59.7)	(202.7)	(143.0)	(97.9)
Operating expenses	3.7	5.3	13.8	17.2
Selling, general and administrative expenses	22.2	21.1	36.6	54.0
Other (income) expense net	(15.9)	(2.7)	(21.6)	18.2
Segment loss	$ (69.7)	$ (226.4)	$ (171.8)	$ (187.3)

Three months ended September 30, 2006 vs. three months ended September 30, 2005

The $264.4 million decrease in *realized revenues* is primarily due to a decrease in both power and natural gas realized revenues. Realized revenues represent (1) revenue from the sale of commodities or completion of energy-related services and (2) gains and losses from the net financial settlement of derivative contracts.

Power and natural gas realized revenues decreased primarily due to a 20 percent decrease in power sales volumes and a 22 percent decrease in average natural gas sales prices. Power sales volumes decreased because certain long-term physical contracts were not replaced due to reducing the scope of trading activities subsequent to 2002. Natural gas sales prices decreased primarily due to a reduction in demand associated with milder weather. The decrease in realized revenues is partially offset by an 11 percent increase in natural gas sales volumes.

Net forward unrealized mark-to-market gains and losses represent changes in the fair values of certain derivative contracts with a future settlement or delivery date that have not been designated as cash flow hedges and the impact of the ineffectiveness of cash flow hedges. The effect of a change in forward prices on natural gas contracts not designated as cash flow hedges primarily caused the $125.6 million increase in *net forward unrealized mark-to-market gains (losses).*

Forward natural gas prices increased in third-quarter 2005, resulting in a loss on our net forward natural gas sales position. Forward natural gas prices decreased in third-quarter 2006, resulting in a gain on our net forward natural gas sales position. An unfavorable change in the ineffectiveness of derivatives designated as cash flow hedges partially offset the increase in *net forward unrealized mark-to-market gains (losses)*. This unfavorable change was due to reduced locational pricing differences between the hedging derivative and the hedged item.

The $281.8 million decrease in Power s *cost of sales* is primarily due to a 20 percent decrease in power purchase volumes and a 22 percent decrease in average natural gas purchase prices. The decrease in cost of sales is partially offset by a 10 percent increase in natural gas purchase volumes. Also offsetting the decrease is a $13 million lower of cost or market adjustment on natural gas inventory held in storage.

Management s Discussion and Analysis (Continued)

The increase in *other (income) expense net* is due to a $12.7 million reduction of contingent obligations associated with our former distributive power generation business.

The $156.7 million decrease in *segment loss* is primarily due to the favorable change in forward natural gas prices. Partially offsetting the decrease is the $13 million lower of cost or market inventory adjustment.

Nine months ended September 30, 2006 vs. nine months ended September 30, 2005

The $429.7 million decrease in *realized revenues* is primarily due to a decrease in power realized revenues associated with a 20 percent decrease in power sales volumes. Power sales volumes decreased because certain long-term physical contracts were not replaced due to the reduction of trading activity subsequent to 2002.

The effect of a change in forward prices on power contracts not designated as cash flow hedges and an unfavorable change in the ineffectiveness of derivatives designated as cash flow hedges primarily caused the $113.2 million decrease in *net forward unrealized mark-to-market gains (losses).*

A 2005 increase in forward power prices caused gains on the net forward purchase position, while a 2006 decrease in forward power prices caused losses on the net forward power purchase contracts. The unfavorable change in ineffectiveness was due to reduced locational pricing differences between the hedging derivative and the hedged item.

The $497.8 million decrease in Power s cost of sales is primarily due to a 21 percent decrease in power purchase volumes. Partially offsetting the decrease is a $20 million lower of cost or market adjustment on natural gas inventory held in storage.

The decrease in *SG&A expenses* is due primarily to a $24.8 million gain from the sale of certain Enron receivables to a third party in 2006.

Other (income) expense net in 2006 includes the $12.7 million reduction of contingent obligations associated with our former distributive power generation business while 2005 includes a $13.5 million accrual for estimated litigation contingencies and a $4.6 million accrual for a regulatory settlement.

The $24.8 million gain from the sale of Enron receivables and the absence of the $13.5 million accrual for litigation contingencies in 2005 primarily caused the $15.5 decrease in *segment loss*. An unfavorable change in forward power prices and ineffectiveness partially offset the decrease, as well as the $20 million lower of cost or market inventory adjustment.

Other

Outlook for the Remainder of 2006

The management of Longhorn completed a sale of the pipeline during the third quarter of 2006. As a result, we received full payment of the $10 million secured bridge loan that we provided Longhorn during 2005.

We continue to receive payments associated with the 2005 transfer of the Longhorn operating agreement to a third party. These payments totaled approximately $1.2 million and $2.7 million for the three and nine months ended September 30, 2006, respectively. Any ongoing payments received or through monetization of the contract will be recognized as income when received. These ongoing payments were not impacted by the sale of the pipeline.

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(Millions)		(Millions)	
Segment revenues	$ 6.4	$ 6.3	$ 19.8	$ 19.4
Segment profit (loss)	$ (.2)	$ (10.1)	$ .1	$ (74.7)

Other segment loss for the three and nine months ended September 30, 2005, includes $9.3 million and $21.5 million, respectively, of equity losses related to our investment in Longhorn. Other segment loss for the nine months ended September 30, 2005, also includes a $49.1 million impairment of our investment in Longhorn and a related $4 million write-off of capitalized project costs.

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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, 2006. We have presented the fair value of assets and liabilities by the period in which we expect them to be realized.

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
$ 25	$1	$(1)	$-	$-	$25

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 Power s forecasted purchases of gas, purchases and sales of power related to its long-term structured contracts and owned generation, Exploration & Production s forecasted sales of natural gas production and Midstream s forecasted sales of natural gas liquids. Certain of Power s other derivatives have not been designated as or do not qualify as SFAS 133 cash flow hedges. The chart below reflects the fair value of derivatives held for nontrading purposes as of September 30, 2006, for the Power, Exploration & Production and Midstream businesses. Of the total fair value of nontrading derivatives, SFAS 133 cash flow hedges had a net asset value of $371 million as of September 30, 2006, which includes the existing fair value of the derivatives at the time of their designation as SFAS 133 cash flow hedges.

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
$ 42	$209	$129	$22	$-	$402

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, 2006, we held collateral support, including letters of credit, of $599 million.

The gross credit exposure from our derivative contracts as of September 30, 2006, is summarized below.

Counterparty Type	Investment Grade (a)	Total
	(Millions)	

Gas and electric utilities	$ 361.2	$ 362.9
Energy marketers and traders	511.3	2,088.5
Financial institutions	2,597.4	2,597.4
Other	26.4	26.7
	$ 3,496.3	5,075.5
Credit reserves		(25.1)
Gross credit exposure from derivatives		$ 5,050.4

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Management s Discussion and Analysis (Continued)

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. The net credit exposure from our derivatives as of September 30, 2006, is summarized below.

Counterparty Type	Investment Grade (a)	Total
	(Millions)	
Gas and electric utilities	$ 177.7	$ 177.9
Energy marketers and traders	279.1	589.1
Financial institutions	198.9	198.9
Other	23.8	23.8
	$ 679.5	989.7
Credit reserves		(25.1)
Net credit exposure from derivatives		$ 964.6

(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 2006, 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, and working capital requirements through cash flow from operations, which is currently estimated to be between $1.5 billion and $1.8 billion in 2006, 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 2006 positioned for growth through disciplined investments in our natural gas businesses. Examples of this planned growth include:

- Gas Pipeline will continue to expand its system to meet the demand of growth markets. Additionally, Northwest Pipeline is constructing an 80-mile pipeline loop, which replaces most of the capacity previously served by 268 miles of pipeline in the Washington state area. Construction is substantially complete and all of the facilities are expected to be in service by November 15, 2006. The project has an estimated cost of $333 million.

- Exploration & Production s March 2005 operating lease agreement will provide access to ten new drilling rigs each for a lease term of three years that will allow us to accelerate the pace of developing our natural gas reserves in the Piceance basin through both deployment of the additional rigs and the rigs designed drilling and operational efficiencies. Through October 2006, we have received the first eight rigs.

- 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 $2.2 billion to $2.4 billion in 2006, with approximately $.4 billion to $.6 billion to be incurred over the remainder of the year. As a result of increasing our development drilling program, primarily in the Piceance basin, $1.2 billion to $1.3 billion of the total estimated 2006 capital expenditures is related to Exploration & Production. Also within the total estimated expenditures for 2006 is approximately $651 million to $711 million for maintenance-related projects at Gas Pipeline, including pipeline replacement and 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 288 MMcfe per day of its remaining expected 2006 production. Power has entered into various sales contracts that economically cover substantially all of its fixed demand obligations through 2010. Midstream has also initiated the use of commodity hedging strategies as part of our efforts to manage commodity price risks on an enterprise basis.

- Sensitivity of margin requirements associated with our marginable commodity contracts. As of September 30, 2006, we estimate our exposure to additional margin requirements through the remainder of 2006 to be no more than $297 million, using a statistical analysis at a 99 percent confidence level.

- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 11 of Notes to Consolidated Financial Statements).

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Management s Discussion and Analysis (Continued)

Overview

In November 2005, we initiated an offer to induce conversion of up to $300 million of the 5.5 percent junior subordinated convertible debentures into our common stock. The conversion was executed in January 2006 and approximately $220.2 million of the debentures were exchanged for common stock. We paid $25.8 million in premiums that are included in *early debt retirement costs* in the Consolidated Statement of Income. See Note 10 of Notes to Consolidated Financial Statements for further information.

In April 2006, Transco issued $200 million aggregate principal amount of 6.4 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement to fund general corporate expenses and capital expenditures. In October 2006, Transco completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

In April 2006, we retired a secured floating-rate term loan for $488.9 million, including outstanding principal and accrued interest. The loan was due in 2008 and secured by substantially all of the assets of Williams Production RMT Company. The loan was retired using a combination of cash and revolving credit borrowings.

In May 2006, we replaced our $1.275 billion secured revolving credit facility with a $1.5 billion unsecured revolving credit facility. The new facility contains similar terms and financial covenants as the secured facility, but contains certain additional restrictions (see Note 9 of Notes to Consolidated Financial Statements).

In June 2006, Northwest Pipeline issued $175 million aggregate principal amount of 7 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement to fund general corporate expenses and capital expenditures. In October 2006, Northwest Pipeline completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

In June 2006, we reached an agreement-in-principle to settle class-action securities litigation filed on behalf of purchasers of our securities between July 24, 2000 and July 22, 2002, for a total payment of $290 million to plaintiffs, subject to court approval. The settlement will be funded from a combination of insurance proceeds and a $145 million cash payment that was made on November 1, 2006. This settlement will not have a material effect on our liquidity position (see Note 11 of Notes to Consolidated Financial Statements for further information).

On June 1, 2006, the FERC entered its final order (FERC Final Order) concerning the Trans-Alaska Pipeline System (TAPS) Quality Bank litigation. The Quality Bank Administrator will determine and invoice for amounts due based on the FERC Final Order, subject to the final disposition of the FERC Final Order appeals. We estimate that our net obligation could be as much as $115 million (see Note 11 of Notes to Consolidated Financial Statements).

In June 2006, Williams Partners L.P. completed its acquisition of 25.1 percent of our interest in Williams Four Corners LLC for $360 million. The acquisition was completed after successfully closing a $150 million private debt offering of senior unsecured notes due 2011 and an equity offering of approximately $225 million in net proceeds. The debt and equity issued by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively. Williams Four Corners LLC owns certain gathering, processing and treating assets in the San Juan Basin in Colorado and New Mexico.

Credit ratings

On May 4, 2006, Standard & Poor s raised our senior unsecured debt rating from a B+ to a BB- with a positive ratings outlook. 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 it s ratings with a + or a - sign to show the obligor s relative standing within a major rating category.

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Management s Discussion and Analysis (Continued)

On June 7, 2006, Moody s Investors Service raised our senior unsecured debt rating from a B1 to a Ba2 with a stable ratings outlook. 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.

On May 15, 2006, Fitch raised our senior unsecured rating from BB to BB+ with a stable ratings outlook. 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.

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 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, 2006 (Millions)
Cash and cash equivalents*	$	1,074.6
Auction rate securities and other liquid securities		159.9
Available capacity under our four unsecured revolving and letter of credit facilities totaling $1.2 billion		257.9
Available capacity under our $1.5 billion unsecured revolving and letter of credit facility**		1,454.4
	$	2,946.8

* *Cash and cash equivalents* includes $77.4 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 $368 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.

Additional Liquidity

Northwest Pipeline and Transco have shelf registration statements available for the issuance of up to $350 million aggregate principal amount of debt securities. The ability of Northwest Pipeline to utilize these registration statements to issue debt securities is restricted by certain covenants of its debt agreements. If the credit rating of Northwest Pipeline or Transco is below investment grade, 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 up to $1.5 billion aggregate principal amount of debt and limited partnership unit securities.

In addition, at the parent-company level, we have filed a shelf registration statement that allows us to issue publicly registered debt and equity securities as needed. This registration statement, filed May 19, 2006, replaces our previously filed shelf registration.

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Management s Discussion and Analysis (Continued)

Sources (Uses) of Cash

	Nine months ended September 30, 2006	Nine months ended September 30, 2005
	(Millions)	
Net cash provided (used) by:		
Operating activities *	$ 1,314.3	$ 1,082.3
Financing activities	(73.3)	117.3
Investing activities	(1,763.6)	(769.1)
Increase (decrease) in cash and cash equivalents	$ (522.6)	$ 430.5

* Includes $6.6 million related to discontinued operations

Operating activities

Our *net cash provided by operating activities* for the nine months ended September 30, 2006, increased from the same period in 2005 due largely to higher operating income at Midstream.

Financing activities

During January 2005, we retired $200 million of 6.125 percent notes issued by Transco, which matured January 15, 2005. In the first quarter of 2005, we received approximately $273 million in proceeds from the issuance of common stock purchased under the FELINE PACS equity forward contracts. During August 2005, we completed an initial public offering of approximately 40 percent of our interest in Williams Partners L.P. resulting in net proceeds of $111 million.

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

See Overview for a discussion of 2006 debt issuances, debt retirement, and additional financing through Williams Partners L.P.

Quarterly dividends paid on common stock were 9 cents per common share during the third quarter of 2006 and totaled $151.8 million for the nine months ended September 30, 2006. For the third quarter of 2005, dividends paid on common stock were 7.5 cents per share and totaled $100 million for the nine months ended September 30, 2005. Dividends paid on common stock were increased to 7.5 cents during the third-quarter 2005, up from the quarterly amount of 5 cents per common share paid during the first and second quarters of 2005.

Investing activities

During the first nine months of 2006, capital expenditures totaled $1,758.9 million and were primarily related to Exploration & Production s increased drilling activity, mostly in the Piceance basin.

During the first nine months of 2006, we purchased $375.8 million and received $319.8 million from the sale of auction rate securities. These are utilized as a component of our overall cash management program.

In January 2005, Northwest Pipeline received an $87.9 million contract termination payment, representing reimbursement of the net book value of the related assets.

In January 2005, we received approximately $54.7 million proceeds from the sale of our WilTel note.

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

We have various other guarantees and commitments which are disclosed in Note 11 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.

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 2006 (see Note 9 of Notes to Consolidated Financial Statements).

Commodity Price Risk

We are exposed to the impact of market fluctuations in the price of natural gas, electricity, refined products 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 non-derivative 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 No. 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. Only derivative contracts are carried at fair value on the balance sheet. Our value at risk for contracts held for trading purposes was approximately \$2 million at September 30, 2006, and \$4 million at December 31, 2005.

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 Natural gas liquids sales
Power	Natural gas purchases and sales Electricity purchases and sales

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The value at risk for derivative contracts held for nontrading purposes was $16 million at September 30, 2006, and $28 million at December 31, 2005. Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS No. 133. We do not consider the underlying commodity positions to which the cash flow hedges relate in our value-at-risk model. Therefore, value at risk does not represent economic losses that could occur on a total nontrading portfolio that includes the underlying commodity positions.

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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 2006 Changes in Internal Controls Over Financial Reporting

There have been no changes during the third-quarter 2006, that have materially affected, or are reasonably likely to materially affect, our Internal Controls over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information called for by this item is provided in Note 11 Contingent Liabilities and Commitments included in the 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, 2005 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:

Risks Related to the Current Geopolitical Situation

Our investments and projects located outside of the United States expose us to risks related to laws of other countries, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments. These risks might delay, reduce or prevent our realization of value from our international projects.

We currently own and might acquire and/or dispose of material energy-related investments and projects outside the United States. The economic and political conditions in certain countries where we have interests or in which we might explore development, acquisition or investment opportunities present risks of delays in construction and interruption of business, as well as risks of war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, that are greater than in the United States. The uncertainty of the legal environment in certain foreign countries in which we develop or acquire projects or make investments could make it more difficult to obtain non-recourse project or other financing on suitable terms, could adversely affect the ability of certain customers to honor their obligations with respect to such projects or investments and could impair our ability to enforce our rights under agreements relating to such projects or investments. Although we do not conduct any operations in Bolivia, if developments similar to those that occurred earlier this year in Bolivia were to occur in other South American countries, it could have a material negative impact on our operations.

Operations in foreign countries also can present currency exchange rate and convertibility, inflation and repatriation risk. In certain conditions under which we develop or acquire projects, or make investments, economic and monetary conditions and other factors could affect our ability to convert our earnings denominated in foreign currencies. In addition, risk from fluctuations in currency exchange rates can arise when our foreign subsidiaries expend or borrow funds in one type of currency but receive revenue in another. In such cases, an adverse change in exchange rates can reduce our ability to meet expenses, including debt service obligations. Foreign currency risk can also arise when the revenues received by our foreign subsidiaries are not in U.S. dollars. In such cases, a strengthening of the U.S. dollar could reduce the amount of cash and income we receive from these foreign subsidiaries. We have put contracts in place to mitigate our most significant foreign currency exchange risks. We have some exposures that are not hedged which could result in losses or volatility in our earnings.

Item 6. Exhibits

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

Exhibit 3.2 Restated By-Laws (filed as Exhibit 3.2 to our Form 8-K filed September 15, 2006).

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.

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.

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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 2, 2006