WILLIAMS COMPANIES INC
Form 10-Q
May 04, 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 March 31, 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 April 30, 2006
Common Stock, $1 par value	595,155,837 Shares

The Williams Companies, Inc.
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Certain matters discussed in this report, excluding historical information, include forward-looking statements statements that 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.

Forward-looking statements can be identified by various forms of words such as anticipates, believes, expects, planned, scheduled, could, may, should, continues, estimates, forecasts, might, potential, projec expressions. Although we believe these forward-looking statements are based on reasonable assumptions, statements made regarding future results are subject to a number of assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this document. Additional information about issues that could cause actual results to differ materially from forward-looking statements is contained in our 2005 Form 10-K.

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

(Dollars in millions, except per-share amounts)	Three months ended March 31, 2006	2005
Revenues:		
Exploration & Production	$ 356.0	$ 249.0
Gas Pipeline	334.0	335.3
Midstream Gas & Liquids	979.4	807.0
Power	2,053.2	2,064.9
Other	6.9	7.0
Intercompany eliminations	(702.0)	(509.2)
Total revenues	3,027.5	2,954.0
Segment costs and expenses:		
Costs and operating expenses	2,588.7	2,390.3
Selling, general and administrative expenses	71.0	73.5
Other income net	(22.3)	(1.8)
Total segment costs and expenses	2,637.4	2,462.0
General corporate expenses	31.8	28.0
Operating income (loss):		
Exploration & Production	142.6	100.2
Gas Pipeline	127.2	156.0
Midstream Gas & Liquids	141.6	121.5
Power	(22.3)	113.0
Other	1.0	1.3
General corporate expenses	(31.8)	(28.0)
Total operating income	358.3	464.0
Interest accrued	(162.8)	(164.7)
Interest capitalized	3.0	1.1
Investing income	46.9	31.0
Early debt retirement costs	(27.0)	
Minority interest in income of consolidated subsidiaries	(7.1)	(5.2)
Other income net	8.1	5.5
Income from continuing operations before income taxes	219.4	331.7
Provision for income taxes	88.3	129.5

Income from continuing operations		131.1		202.2
Income (loss) from discontinued operations		.8		(1.1)
Net income	$	131.9	$	201.1
Basic earnings per common share:				
Income from continuing operations	$	.22	$	.36
Income (loss) from discontinued operations				
Net income	$	.22	$	.36
Weighted-average shares (thousands)		591,407		564,437
Diluted earnings per common share:				
Income from continuing operations	$	.22	$	.34
Income (loss) from discontinued operations				
Net income	$	.22	$	.34
Weighted-average shares (thousands)		607,073		599,422
Cash dividends per common share	$	.075	$	.05

See accompanying notes.

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

(Dollars in millions, except per-share amounts)	March 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,115.0	$ 1,597.2
Restricted cash	80.2	92.9
Accounts and notes receivable (net of allowance of $25 in 2006 and $86.6 in 2005)	1,173.7	1,613.8
Inventories	277.8	272.6
Derivative assets	3,260.0	5,299.7
Margin deposits	307.7	349.2
Assets of discontinued operations	12.8	12.8
Deferred income taxes	208.7	241.0
Other current assets and deferred charges	328.9	218.1
Total current assets	6,764.8	9,697.3
Restricted cash	38.2	36.5
Investments	879.1	887.8
Property, plant and equipment net	12,682.5	12,409.2
Derivative assets	3,865.1	4,656.9
Goodwill	1,014.5	1,014.5
Other assets and deferred charges	784.8	740.4
Total assets	$ 26,029.0	$ 29,442.6
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 994.4	$ 1,360.6
Accrued liabilities	972.5	1,121.9
Customer margin deposits payable	129.1	320.7
Liabilities of discontinued operations	1.3	1.2
Derivative liabilities	3,282.5	5,523.2
Long-term debt due within one year	175.7	122.6
Total current liabilities	5,555.5	8,450.2
Long-term debt	7,252.8	7,590.5
Deferred income taxes	2,662.9	2,508.9
Derivative liabilities	3,471.8	4,331.1
Other liabilities and deferred income	947.0	920.3
Contingent liabilities and commitments (Note 11)		
Minority interests in consolidated subsidiaries	213.5	214.1

Stockholders equity:		
Common stock (960 million shares authorized at $1 par value; 600.7 million issued at March 31, 2006 and 579.1 million shares issued at December 31, 2005)	600.7	579.1
Capital in excess of par value	6,535.7	6,327.8
Accumulated deficit	(1,048.6)	(1,135.9)
Accumulated other comprehensive loss	(121.0)	(297.8)
Other	(.1)	(4.5)
	5,966.7	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	5,925.5	5,427.5
Total liabilities and stockholders equity	$ 26,029.0	$ 29,442.6

See accompanying notes.

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

	Three months ended March 31,	
(Dollars in millions)	**2006**	**2005**
OPERATING ACTIVITIES:		
Income from continuing operations	$ 131.1	$ 202.2
Adjustments to reconcile to cash provided by operations:		
Depreciation, depletion and amortization	197.0	178.2
Provision for deferred income taxes	74.6	118.9
Provision for loss on investments, property and other assets	2.4	(.5)
Net gain on disposition of assets	(10.3)	(12.8)
Early debt retirement costs	27.0	
Minority interest in income of consolidated subsidiaries	7.1	5.2
Amortization of stock-based awards	10.5	2.8
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	440.5	159.7
Inventories	(5.2)	38.3
Margin deposits and customer margin deposits payable	(150.1)	(4.5)
Other current assets and deferred charges	(46.1)	4.5
Accounts payable	(313.1)	(103.8)
Accrued liabilities	(212.4)	(151.6)
Changes in current and noncurrent derivative assets and liabilities	21.7	(91.7)
Other, including changes in noncurrent assets and liabilities	(10.0)	(40.5)
Net cash provided by operating activities of continuing operations	164.7	304.4
FINANCING ACTIVITIES:		
Payments of long-term debt	(64.1)	(215.5)
Proceeds from issuance of common stock	10.2	288.0
Fees paid to amend credit facilities		(17.9)
Premiums paid on early debt retirement costs	(25.8)	
Dividends paid	(44.6)	(28.5)
Dividends paid to minority interests	(6.6)	(12.6)
Changes in restricted cash	7.3	29.8
Changes in cash overdrafts	(31.0)	15.7
Other net	(1.2)	(.2)
Net cash provided (used) by financing activities of continuing operations	(155.8)	58.8
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(468.3)	(222.9)
Proceeds from dispositions	12.5	6.7
Proceeds from contract termination payment		87.9

Changes in accounts payable and accrued liabilities	14.5	(.5)
Purchases of investments/advances to affiliates	(9.7)	(26.3)
Purchases of auction rate securities	(95.3)	
Proceeds from sales of businesses		.3
Proceeds from sales of auction rate securities	19.4	
Proceeds received on sale of note from WilTel		54.7
Proceeds from dispositions of investments and other assets	31.4	8.6
Other net	4.4	8.3
Net cash used by investing activities of continuing operations	(491.1)	(83.2)
Increase (decrease) in cash and cash equivalents	(482.2)	280.0
Cash and cash equivalents at beginning of period	1,597.2	930.0
Cash and cash equivalents at end of period	$ 1,115.0	$ 1,210.0

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 March 31, 2006, and results of operations and cash flows for the three months ended March 31, 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 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.

Note 3. Asset Sales, Impairments and Other Accruals

Costs and operating expenses and *selling, general and administrative expenses* within our Gas Pipeline segment in 2005 includes $7.5 million and $5.6 million, respectively, of adjustments to reduce costs due to correcting the carrying value of certain liabilities recorded in prior periods.

Other income net in 2006 includes:

- Income within our Midstream Gas & Liquids (Midstream) segment of approximately $9 million related to the settlement of an international contract dispute;

- Income of $2 million associated with the reversal of an accrued litigation contingency due to a favorable court ruling in the Gas Pipeline segment. Associated with this contingency reversal is $5 million of income due to reversing accrued interest, which is included in *interest accrued*.

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Notes (Continued)

Note 4. Provision for Income Taxes

The *provision for income taxes* includes:

	Three months ended March 31, 2006	2005
	(Millions)	
Current:		
Federal	$ 3.1	$ 4.3
State	2.6	5.2
Foreign	8.0	1.1
	13.7	10.6
Deferred:		
Federal	56.4	102.9
State	12.6	16.0
Foreign	5.6	
	74.6	118.9
Total provision	$ 88.3	$ 129.5

The effective income tax rate for the three months ended March 31, 2006, is greater than the federal statutory rate due primarily to the effect of state income taxes.

The effective income tax rate for the three months ended March 31, 2005, is greater than the federal statutory rate due primarily to the effect of state income taxes and an accrual for income tax contingencies, partially offset by net foreign operations.

Note 5. Earnings Per Common Share from Continuing Operations

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

	Three months ended March 31, 2006	2005
	(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)	$ 131.1	$ 202.2
Basic weighted-average shares (2)	591,407	564,437
Effect of dilutive securities:		
Unvested deferred shares (3)	834	2,565
Stock options	4,355	4,872
Convertible debentures	10,477	27,548
Diluted weighted-average shares	607,073	599,422
Earnings per share from continuing operations:		

Basic	$	.22	$	.36
Diluted	$	.22	$	.34

(1) The three months ended March 31, 2006 and 2005 include $1 million and $2.5 million, respectively, of interest expense, net of tax, associated with our convertible debentures. This amount has 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 March 31, 2006, will vest over the period from April 2006 to January 2010.

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Notes (Continued)

The table below includes information related to options that were outstanding at March 31 of each respective year but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the first quarter weighted-average market price of our common shares.

	March 31, 2006	March 31, 2005
Options excluded (millions)	4.6	9.0
Weighted-average exercise prices of options excluded	$ 35.35	$ 28.45
Exercise price ranges of options excluded	$ 22.68-$42.29	$ 18.15-$42.29
First quarter weighted-average market price	$ 22.40	$ 17.51

In addition, 3.2 million options with exercise prices less than the first quarter weighted-average market price have been excluded from the computation of weighted-average stock options due to the shares being anti-dilutive as a result of our adoption of Financial Accounting Standards Board (FASB) Statement No. 123(R), Share-Based Payment (SFAS No. 123(R)), during the first quarter of 2006 (see Note 7). These excluded shares have a weighted-average exercise price of $19.30.

Note 6. Employee Benefit Plans

Net periodic pension expense and other postretirement benefit expense for the three months ended March 31, 2006 and 2005 are as follows:

	Pension Benefits Three months ended March 31,		Other Postretirement Benefits Three months ended March 31,	
	2006	2005	2006	2005
	(Millions)			
Components of net periodic pension and other postretirement benefit expense:				
Service cost	$ 5.7	$ 6.1	$ .9	$ .9
Interest cost	11.8	12.0	5.2	3.7
Expected return on plan assets	(16.9)	(15.2)	(2.9)	(3.3)
Amortization of prior service credit	(.1)	(.4)	(.1)	(1.2)
Recognized net actuarial loss	3.8	3.2	.9	
Regulatory asset amortization	(.1)	.5	1.6	1.6
Settlement/curtailment expense		1.9		
Net periodic pension and other postretirement benefit expense	$ 4.2	$ 8.1	$ 5.6	$ 1.7

Through March 31, 2006, we have contributed $2.4 million to our pension plans and $3.7 million to our other postretirement benefit plans. We presently anticipate contributing approximately $18 million more to our pension plans in 2006 for a total of approximately $20 million. We presently anticipate contributing approximately $12 million more to our other postretirement benefit plans in 2006 for a total of approximately $16 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 March 31, 2006, 43.8 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 19.5 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 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 three months ending March 31, 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 SFAS No. 123(R), using the modified-prospective method. Under this method, compensation cost recognized in the first quarter 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 all 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). Results for prior periods have not been restated. Total stock-based compensation expense for first-quarter 2006 was $10.5 million, which includes a $.3 million reduction of previously recognized compensation cost for deferred share awards related to the estimated number of awards expected to be forfeited. This $.3 million adjustment was not considered material for reporting as the cumulative effect of a change in accounting principle. Measured but unrecognized stock-based compensation expense at March 31, 2006, was approximately $80 million, which is comprised of approximately $26 million related to stock options and approximately $54 million related to deferred shares. These amounts are expected to be recognized over a weighted average period of 2.2 years.

As a result of adopting SFAS No. 123(R), our *income from continuing operations before income taxes* and *net income* for the quarter ending March 31, 2006, are approximately $6 million and $4 million lower, respectively, than if we continued to account for share-based compensation under APB No. 25. Basic earnings per share is $.01 per share lower due to implementation of SFAS No. 123(R).

The following table illustrates the effect on *net income* and *earnings per common share* if the company had applied the fair value recognition provisions to SFAS No. 123 to options granted under the Plan for the quarter ending March 31, 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 March 31, 2005 (Dollars in millions, except per share amounts)	
Net income, as reported	$	201.1
Add: Stock-based employee compensation expense included in the Consolidated Statement of Income, net of related tax effects		1.8
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects		(5.5)
Pro forma net income	$	197.4
Earnings per share:		
Basic-as reported	$	.36
Basic-pro forma	$	.35
Diluted-as reported	$	.34
Diluted-pro forma	$	.33

Stock Options

Stock options are valued at the date of award 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 quarter ending March 31, 2006.

Stock Options	Options (Millions)	Weighted-Average Exercise Price	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2005	20.4	$ 16.63	
Granted	1.1	$ 21.67	
Exercised	(.9)	$ 11.18	$ 10.2
Cancelled	(.2)	$ 28.79	
Outstanding at March 31, 2006	20.4	$ 17.05	$ 168.7
Exercisable at March 31, 2006	15.7	$ 17.12	$ 142.0

The following summary provides additional information about stock options that are outstanding and exercisable at March 31, 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	9.7	$ 7.19	6.4	8.3	$ 6.76	6.2
$10.38 to $16.40	1.3	$ 15.47	3.9	1.3	$ 15.54	3.8
$17.10 to $31.58	5.9	$ 21.34	7.3	2.6	$ 22.90	4.7
$33.51 to $42.28	3.5	$ 37.66	2.1	3.5	$ 37.66	2.1
Total	20.4	$ 17.05	5.8	15.7	$ 17.12	4.9

The estimated weighted average grant-date fair value of stock options granted in the first quarter of 2006 is $8.37 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 quarter of 2006 were estimated using the following assumptions:

Assumptions:	
Expected dividend yield	1.4%
Expected volatility	36.3%
Risk-free interest rate	4.63%
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 $10.2 million during the first quarter of 2006.

Nonvested Deferred Shares

Deferred shares are 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 quarter ending March 31, 2006.

Deferred Shares	**Shares**	**Weighted Average Grant-Date Fair Value**
	(Millions)	
Nonvested at December 31, 2005	2.8	$ 14.60
Granted	1.3	$ 21.68
Vested	(.4)	$ 9.30
Nonvested at March 31, 2006	3.7	$ 17.55

The total market value of shares vested and issued during the quarter was approximately $8 million.

Performance-based share awards issued under the Plan represent 35 percent of nonvested deferred shares outstanding at March 31, 2006. These awards are 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 March 31, 2006 and December 31, 2005 are as follows:

	March 31, 2006	**December 31, 2005**
	(Millions)	
Natural gas in underground storage	$ 115.0	$ 90.4
Materials, supplies and other	83.6	82.2
Natural gas liquids	79.2	100.0
	$ 277.8	$ 272.6

Note 9. Debt and Banking Arrangements

Long-Term Debt

Revolving credit and letter of credit facilities (credit facilities)

At March 31, 2006, no loans are outstanding under these facilities. Letters of credit issued under these facilities are:

	Letters of Credit at March 31, 2006
	(Millions)
$500 million unsecured credit facilities	$ 458.0
$700 million unsecured credit facilities	$ 552.2
$1.275 billion secured credit facility	$ 115.3

In May 2006, we replaced our $1.275 billion secured credit facility with a $1.5 billion unsecured revolving credit facility. The new facility contains similar terms and covenants as the secured facility.

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).

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Notes (Continued)

In April 2006, Transcontinental Gas Pipe Line Corporation (Transco) issued $200 million aggregate principal amount of 6.4 percent senior notes due 2016 to certain institutional investors in a private debt placement. Transco intends to use the net proceeds for general corporate purposes and the funding of capital expenditures.

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. We anticipate refinancing a portion of this issue at the corporate parent level on an unsecured basis later this year.

We have entered into an agreement with Williams Partners L.P. for its acquisition of a 25.1 percent interest in Williams Four Corners, LLC, which will own our gathering and processing assets in the Four Corners area, for $360 million. Williams Partners L.P. plans to finance its payment of the cash purchase price through a combination of debt and equity, as detailed in its registration statement on Form S-1 filed with the Securities and Exchange Commission on April 7, 2006. The closing of the transaction is subject to the satisfaction of a number of conditions, including the ability of Williams Partners L.P. to obtain financing and the receipt of all necessary consents. Closing is expected to occur in the second quarter of 2006. The debt issued by Williams Partners L.P. will be reported as a component of our consolidated debt balances.

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 March 31, 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 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 $26 million at March 31, 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, are now pending before the Ninth Circuit Court of Appeals. As part of the State Settlement, an additional $60 million,

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Notes (Continued)

previously accrued, remains to be paid to the California Attorney General (or his designee) over the next five 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. Two 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:

- Federal court in New York based on an allegation of manipulation of the NYMEX gas market. We reached a settlement of this matter for $9.15 million which we paid into escrow in April 2006 subject to final court approval. The court has granted preliminary approval, and the request for final court approval is pending.

- 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. We have reached settlement of this matter for $15.6 million. Legal documents will be filed with the court and the settlement is subject to court approval.

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

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

It is reasonably possible that additional amounts may be necessary to resolve the remaining outstanding litigation in this area.

Mobile Bay Expansion

In December 2002, an administrative law judge at the FERC issued an initial decision in Transco s 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 $82 million, excluding interest, through March 31, 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. Under the sales agreement, the purchaser of the claims may demand repayment of the purchase price for the reduced portions of the claims. We are negotiating with the purchaser regarding potential payment obligations.

Notes (Continued)

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 March 31, 2006, we had accrued liabilities of $14 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 to bring the sites up to Washington s current environmental standards. At March 31, 2006, we have accrued liabilities totaling approximately $4 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline s rates.

We also accrue environmental remediation costs for our natural gas gathering and processing facilities, primarily related to soil and groundwater contamination. At March 31, 2006, we have accrued liabilities totaling approximately $7 million for these costs.

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.

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. We are currently evaluating the NOV and preparing our response to the CDPHE.

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, on April 27, 2006, the DOJ requested a joint meeting with Magellan and us to discuss the Magellan obligations and our obligations including two 2006 spills at our Colorado and Wyoming facilities.

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

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Notes (Continued)

costs exceed a specified amount. At March 31, 2006, we have accrued liabilities of approximately $11 million for such excess costs.

We are in a dispute with a defendant that was involved 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 seeks 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 arbitration is expected to occur in the second quarter of 2006. Under the arbitration format, the arbitrator must choose without any modification either our $1 million final offer or the defendant s approximately $20 million final offer.

Other

At March 31, 2006, we have accrued environmental liabilities totaling approximately $27 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. On February 2, 2006, the DOJ confirmed our agreement-in-principle to resolve the government s claims against us for alleged violations. We also reached an agreement-in-principle to resolve an indemnity dispute in connection with the 2003 sale of the Memphis refinery.

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 (WFS), 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. The current owner has asserted an indemnification claim to us for payment of the penalty. We are analyzing the proposed penalty and negotiating a resolution with the current plant owner and the ODEQ.

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.

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Notes (Continued)

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.

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 and Texas Gas Transmission Corporation, 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 has 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, including the action filed in federal court in Colorado against us. 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 remain 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. The District Court is considering whether to affirm or reject the special master s recommendations and heard oral arguments on December 9, 2005.

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 has been set for May 2006, but the parties have

Notes (Continued)
negotiated an agreement dismissing the measurement claims and deferring further proceedings on the royalty claims until resolution of an appeal in another case.

Securities class actions

Numerous shareholder class action suits were filed against us in 2002 in the United States District Court for the Northern District of Oklahoma. The majority of the suits 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. The parties have substantially completed discovery, and the trial date is currently set for August 16, 2006. Preliminary settlement discussions have occurred. 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. We have directors and officers insurance which we believe provides coverage for these claims. However, it is reasonably possible that the ultimate resolution of this litigation will include some amount outside of insurance coverage. Based on the status of proceedings through the date of this filing, a reasonable estimate of such amount cannot be determined.

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 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. Based on our computation and assessment of ultimate ruling terms that would be considered probable, we recorded an accrual of approximately $134 million in the third quarter of 2004. Because the application of certain aspects of the initial decisions are subject to interpretation, we have calculated the reasonably possible impact of the decisions, if fully adopted by the FERC and

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RCA, to result in additional exposure to us of approximately $32 million more than we have accrued at March 31, 2006.

On October 20, 2005, the FERC and the RCA issued substantially similar orders regarding the initial decisions. Consistent with the 2005 Highway Reauthorization Bill enacted on August 10, 2005, the two orders eliminate our retroactive exposure for refunds prior to February 1, 2000. The orders also generally affirm the initial decisions except for some modifications to the residual product cuts valuation methodology. We believe the overall impact of the change in retroactive periods precludes our previously disclosed concerns for reasonably possible exposure for amounts in addition to those currently accrued.

In November 2005, ExxonMobil appealed the FERC s decision 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 have appealed the FERC s order to the extent of its ruling on the West Coast Heavy Distillate component. Decisions on these appeals are not expected until late 2006 at the earliest.

On March 30, 2006, the FERC issued its rehearing order and the following day the RCA adopted the FERC s order. Although the orders included some clarifications and adjustments, the commencement date for retroactive refund exposure was unchanged. We are still analyzing the impact of the clarifications and changes; however we do not believe the orders will result in a material change to our accrued liability, subject to the appeals mentioned above.

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. On the same date, Power was served with a subpoena from the city related to the tax assessment. During July 2005, the city held hearings on this matter. 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 Power and AES Redondo Beach have filed notices of appeal that will be heard at the city level pursuant to a schedule that calls for a final determination by May 19, 2006. On December 19, 2005, Power received additional assessments from the city totaling approximately $3 million in taxes (inclusive of interest and penalties) for the period from October 1, 2004 through September 30, 2005. In late January, 2006, we received an additional assessment totaling approximately $270,000 (inclusive of interest and penalties) for the period from October 1, 2005 through December 31, 2005. Power and AES Redondo Beach have objected to these assessments and have requested a hearing on them. We believe that under Power s 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 they do not agree. On April 24, 2006, Williams Power filed a motion to intervene in a refund action brought by AES Redondo in Los Angeles Superior Court related to certain taxes paid since the 2005 notice of assessment. A hearing has been scheduled for May 22, 2006.

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 Louisiana and Texas. In January 2002, NAICO added Gulf Liquids co-venturer Power to the suits as a third-party defendant. Gulf Liquids has 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. The contractors and sureties are asserting both contract and tort claims, some of which appear to be duplicative, against Gulf Liquids, Power, and others. The requested contractual and extra-contractual damages range from $20 million to $90 million.

The cases filed in Harris County, Texas, have been consolidated. Various motions for summary judgment are pending before the court. Depending in part on the resolution of these various motions, it is reasonably possible that the contractors and sureties might be awarded damages against us in these various cases for an amount up to $25

Notes (Continued)

million. The trial in the Harris County cases began on April 25, 2006, and is expected to conclude in the second quarter of 2006.

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 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 request that the court allow the lawsuits to proceed as class actions and seek legal and equitable relief in an unspecified amount. On April 17, 2006, all defendants, including us, filed their joint motion to dismiss the class action petitions on various grounds.

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. At March 31, 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.

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 March 31, 2006, Power s estimated committed payments under these contracts range from approximately $311 million to $420 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 $5.8 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

Notes (Continued)

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 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.

A foreign bank is a defendant in litigation related to a loan they provided to us. We have repaid the loan and indemnified the bank for legal fees and potential losses that may result from this litigation. We are unable to determine the maximum amount of future payments that we could be required to pay as it is dependent upon the ultimate resolution of the claim. However, we believe the probability is remote that a judgment will be made against the bank that we will have to pay. The carrying value of this guarantee is $0.3 million at March 31, 2006.

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 $47 million at March 31, 2006. Our exposure declines systematically throughout the remaining term of WilTel s obligations. The carrying value of these guarantees is approximately $42 million at March 31, 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 March 31, 2006.

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 directors for legal fees and potential losses that might result from this litigation. Claims against these 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

Notes (Continued)
the purchaser of MAPCO Inc. s former subsidiary. This guarantee expires in December 2010 and has no carrying value.

Note 12. Comprehensive Income

Comprehensive income is as follows:

	Three months ended March 31,	
	2006	2005
	(Millions)	
Net income	$ 131.9	$ 201.1
Other comprehensive income (loss):		
Unrealized gains (losses) on derivative instruments	189.0	(328.6)
Net reclassification into earnings of derivative instrument losses	101.4	67.8
Foreign currency translation adjustments	(2.2)	(2.2)
Minimum pension liability adjustment	(.3)	
Other comprehensive income (loss) before taxes	287.9	(263.0)
Income tax (provision) benefit on other comprehensive income (loss)	(111.1)	99.8
Other comprehensive income (loss)	176.8	(163.2)
Comprehensive income	$ 308.7	$ 37.9

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 at March 31, 2006, include net unrealized gains on forward power purchases and sales of approximately $92 million and net unrealized gains on forward natural gas purchases and sales of approximately $97 million. *Unrealized gains on derivative instruments* in the first quarter of 2006 are primarily due to the effect of decreases in forward prices of these commodities. *Unrealized losses on derivative instruments* in the first quarter of 2005 are primarily due to the effect of increases in forward prices of these commodities.

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.

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Notes (Continued)

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

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Power	Other	Eliminations	Total
				(Millions)			
Three months ended March 31, 2006							
Segment revenues:							
External	$ (59.5)	$ 330.5	$ 966.1	$ 1,787.6	$ 2.8	$	$ 3,027.5
Internal	415.5	3.5	13.3	265.6	4.1	(702.0)	
Total revenues	$ 356.0	$ 334.0	$ 979.4	$ 2,053.2	$ 6.9	$ (702.0)	$ 3,027.5
Segment profit (loss)	$ 147.6	$ 134.7	$ 151.5	$ (22.5)	$ 1.0	$	412.3
Less:							
Equity earnings (losses)	5.0	7.5	9.9	(.2)			22.2
Segment operating income (loss)	$ 142.6	$ 127.2	$ 141.6	$ (22.3)	$ 1.0	$	390.1
General corporate expenses							(31.8)
Consolidated operating income							$ 358.3
Three months ended March 31, 2005							
Segment revenues:							
External	$ (27.9)	$ 331.8	$ 796.3	$ 1,851.0	$ 2.8	$	$ 2,954.0
Internal	276.9	3.5	10.7	213.9	4.2	(509.2)	
Total revenues	$ 249.0	$ 335.3	$ 807.0	$ 2,064.9	$ 7.0	$ (509.2)	$ 2,954.0
Segment profit (loss)	$ 103.7	$ 167.4	$ 128.6	$ 114.1	$ (4.1)	$	$ 509.7
Less:							
Equity earnings (losses)	3.5	11.4	7.1	1.1	(5.4)		17.7
Segment operating income	$ 100.2	$ 156.0	$ 121.5	$ 113.0	$ 1.3	$	492.0

General corporate expenses	(28.0)
Consolidated operating income	$ 464.0

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

	Total Assets	
	March 31, 2006	**December 31, 2005**
	(Millions)	
Exploration & Production	$ 8,425.9	$ 8,672.0
Gas Pipeline	7,667.5	7,581.0
Midstream Gas & Liquids	4,777.7	4,677.7
Power (1)	11,004.6	14,989.2
Other	3,516.1	3,929.9
Eliminations	(9,375.6)	(10,420.0)
	26,016.2	29,429.8
Assets of discontinued operations	12.8	12.8
Total	$ 26,029.0	$ 29,442.6

(1) 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.

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. 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. 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. The Issue 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 will

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Notes (Continued)

apply this Issue beginning in the second quarter of 2006. We will assess the impact of this Issue on our consolidated financial statements.

In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments, an amendment of FASB Statements No. 133 and 140. 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. 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. We will assess the impact of this FSP on our Consolidated Financial Statements.

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

Recent Events and 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.

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 are expected to be effective 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);

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.

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.

In April 2006, Transco issued $200 million aggregate principal amount of 6.4 percent senior notes due 2016 to certain institutional investors in a private debt placement. Transco intends to use the net proceeds for general corporate purposes and the funding of capital expenditures.

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. We anticipate refinancing a portion of this issue at the corporate parent level on an unsecured basis later this year.

In May 2006, we replaced our $1.275 billion secured credit facility with a $1.5 billion unsecured revolving credit facility. The new facility contains similar terms and covenants as the secured facility.

We have entered into an agreement with Williams Partners L.P. for its acquisition of a 25.1 percent interest in Williams Four Corners, LLC, which will own our gathering and processing assets in the Four Corners area, for $360 million. Williams Partners L.P. plans to finance its payment of the cash purchase price through a combination of debt and equity, as detailed in its registration

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Management s Discussion & Analysis (Continued)

statement on Form S-1 filed with the Securities and Exchange Commission on April 7, 2006. The closing of the transaction is subject to the satisfaction of a number of conditions, including the ability of Williams Partners L.P. to obtain financing and the receipt of all necessary consents. Closing is expected to occur in the second quarter of 2006. The debt issued by Williams Partners L.P. will be reported as a component of our consolidated debt balances.

Our property insurance coverage levels and premiums have recently been revised. In general, our future coverage levels will be decreasing while our premiums will be increasing. These changes reflect general trends in our industry due to recent hurricane-related damages and will impact us prospectively.

General

Unless indicated otherwise, the following discussion and analysis of Results of Operations and Financial Condition relates to our current continuing operations and should be read in conjunction with the Consolidated Financial Statements and notes thereto included in Item 1 of this document and 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(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 in the first quarter of 2006 was $10.5 million, approximately $6 million of which is related to stock options. Compensation cost recognized in the first quarter of 2005, prior to the adoption of SFAS No. 123(R), was $2.8 million. Measured but unrecognized compensation cost at March 31, 2006, was approximately $80 million, which is comprised of approximately $26 million related to stock options and approximately $54 million related to deferred shares. These amounts are expected to be recognized over a weighted average period of 2.2 years. See Note 7 of Notes to Consolidated Financial Statements for additional information.

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Management s Discussion & Analysis (Continued)

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three months ended March 31, 2006, compared to the three months ended March 31, 2005. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended March 31 ,		% Change from
	2006	2005	2005 *
	(Millions)		
Revenues	$ 3,027.5	$ 2,954.0	+2%
Costs and expenses:			
Costs and operating expenses	2,588.7	2,390.3	-8%
Selling, general and administrative expenses	71.0	73.5	+3%
Other income net	(22.3)	(1.8)	NM
General corporate expenses	31.8	28.0	-14%
Total costs and expenses	2,669.2	2,490.0	
Operating income	358.3	464.0	
Interest accrued net	(159.8)	(163.6)	+2%
Investing income	46.9	31.0	+51%
Early debt retirement costs	(27.0)		NM
Minority interest in income of consolidated subsidiaries	(7.1)	(5.2)	-37%
Other income net	8.1	5.5	+47%
Income from continuing operations before income taxes	219.4	331.7	
Provision for income taxes	88.3	129.5	+32%
Income from continuing operations	131.1	202.2	
Income (loss) from discontinued operations	.8	(1.1)	NM
Net income	$ 131.9	$ 201.1	

* + = 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 March 31, 2006 vs. three months ended March 31, 2005

The $73.5 million increase in *revenues* is due primarily to increased crude and natural gas liquid (NGL) marketing revenues at Midstream and increased domestic revenues at Exploration & Production as both segments experienced increased production and prices.

The $198.4 million increase in *costs and operating expenses* is due largely to increased crude and NGL marketing costs at Midstream associated with the increased production and pricing and increased power and natural gas costs at Power. Additionally, Exploration & Production incurred increased depreciation, depletion and amortization, operating taxes and gas management fees as a result of their increased gas production.

Selling, general and administrative (SG&A) expenses in 2006 reflects a $23.7 million reduction in bad debt expense at Power resulting from the sale of certain Enron receivables to a third party. Offsetting this decrease is the absence of $5.6 million of cost reductions in 2005 related to corrections of the carrying value of certain liabilities at Gas Pipeline, an increase of approximately $6 million, mostly due to higher staffing and overhead costs at Gas Pipeline, and an additional $5 million in costs at Exploration & Production due to increased staffing in support of increased drilling and operational activity and higher compensation.

Other income net within *operating income,* in 2006 includes:

- Income of $9 million due to a settlement of an international contract dispute at Midstream;
- An approximate $4 million gain on sale of idle gas treating equipment at Midstream;
- An approximate $4 million favorable transportation settlement at Midstream;
- Income of $2 million associated with the reversal of an accrued litigation contingency due to a favorable court ruling at Gas Pipeline.

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Management s Discussion & Analysis (Continued)

Other income net, within *operating income*, in 2005 includes:

- A $4.6 million accrual for a regulatory settlement at Power;

- A $7.9 million gain on the sale of a natural gas property at Exploration & Production;

- Gains of $3.7 million from the sales of Exploration & Production s securities, invested in a coal seam royalty trust, which were purchased for resale.

The $15.9 million increase in *investing income* is due to:

- A $12.8 million increase in interest income mostly associated with larger short-term investment balances during a period of rising interest rates;

- Increased equity earnings of $4.5 million due largely to the absence of equity losses in 2006 on our fully impaired Longhorn Partners Pipeline, L.P. (Longhorn) equity investment.

Early debt retirement costs in first quarter 2006 includes $25.8 million in premiums and $1.2 million in fees related to the January 2006 debt conversion (see Note 10 of Notes to Consolidated Financial Statements).

Provision for income taxes decreased by $41.2 million due primarily to lower pre-tax income in first-quarter 2006. The effective income tax rate for first-quarter 2006 is greater than the federal statutory rate due primarily to the effect of state income taxes. The effective income tax rate for first-quarter 2005 is greater than the federal statutory rate due primarily to the effect of state income taxes and an accrual for income tax contingencies, partially offset by lower net foreign operations.

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Management s Discussion & Analysis (Continued)

Results of Operations Segments

Exploration & Production

Overview of Three Months Ended March 31, 2006

In the first quarter of 2006, we continued our strategy to rapidly expand the development of our significant drilling inventory located within our basins. Our major accomplishments for the period include:

- Increased average daily domestic production levels by approximately 16 percent from first quarter last year. The average daily domestic production for the first quarter was approximately 661 million cubic feet of gas equivalent (MMcfe) in 2006 compared to 568 MMcfe in 2005.

Domestic Production Growth

1st Quarter 2006 domestic production grew 16 percent or 93 MMcfe per day over 1st Quarter 2005

- Benefited from higher market prices which, in turn, increased our net realized average prices received for production volumes sold. Net realized average prices include market prices, net of hedge positions, less gathering and transportation expenses. Despite increased derivative hedge losses in the first quarter of 2006, we realized net domestic average prices of $4.71 per thousand cubic feet of gas equivalent (Mcfe) compared with $4.00 per Mcfe in 2005, an increase of approximately 18 percent.

- Increased our development drilling program by 28 percent, surpassing quarterly drilling activities during the first quarter of 2005. We drilled 377 gross wells in the first quarter of 2006 compared to 294 in the first quarter of 2005. Capital expenditures for domestic drilling, development, and acquisition activity in first quarter 2006 were approximately $308 million compared to approximately $156 million in first quarter 2005.

The benefits of higher production volumes and higher net realized average prices were partially offset by increased operating costs. The increase in operating costs was primarily due to escalated overall production and maintenance activities among oil and gas producers, which increased competition for drilling rigs and services in our basins. The increase in hedge losses was primarily due to higher market prices associated with our NYMEX collars and fixed price hedge positions.

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Management s Discussion & Analysis (Continued)

Significant events

Through April 2006, we have placed into service the first four new state-of-the-art FlexRig4® drilling rigs that we are leasing in accordance with a contract entered into with Helmerich & Payne in March 2005. The contract is 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 early January 2006, we increased our position in the Fort Worth basin with a $23.6 million acquisition of producing properties. This increases our diversification into the Mid-Continent region and allows us to use our horizontal drilling expertise to develop wells in the Barnett Shale formation.

In the first quarter of 2006, we entered into various collar agreements at the basin level which, in the aggregate, hedge an additional 150 MMcfe per day for production in 2007 and 100 MMcfe per day for production in 2008.

Outlook for the Remainder of 2006

Our expectations for the remainder of the year include:

- Continuing our development drilling program in our key basins of Piceance, Powder River, San Juan, Arkoma and Fort Worth through our remaining planned capital expenditures projected between $675 and $775 million;

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

- Increasing our 2005 average daily domestic production level of 612 MMcfe by 15 to 20 percent for 2006.

Approximately 301 MMcfe of our forecasted 2006 daily production is hedged in NYMEX and basis fixed price contracts at prices that average $3.82 per Mcfe at a basin level. In addition, we have NYMEX collar agreements totaling 65 MMcfe per day at a floor price of $6.62 per Mcfe to a 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.

Risks to achieving our objectives include drilling rig availability, including timely deliveries of the contracted new rigs, as well as obtaining permits as planned for drilling.

Period-Over-Period Results

	Three months ended March 31,	
	2006	**2005**
	(Millions)	
Segment revenues	$ 356.0	$ 249.0
Segment profit	$ 147.6	$ 103.7

Management s Discussion & Analysis (Continued)

Three months ended March 31, 2006 vs. three months ended March 31, 2005

Total *segment revenues* increased $107.0 million, or 43 percent, primarily due to the following:

- $77 million increase in domestic production revenues reflecting $35 million higher revenues associated with a 16 percent increase in production volumes sold and $42 million higher revenues associated with an 18 percent increase in net realized average prices;

- $13 million increase in revenues from gas management activities, offset in *costs and expenses*;

- $9 million increase in revenues primarily due to an unrealized gain from hedge ineffectiveness attributable to locational pricing differences between our NYMEX derivative hedges and the hedged production;

- $5 million increase in production revenues from our international operations due to increased production volumes and higher average prices.

The higher net realized average prices reflect the benefit of higher market prices for natural gas in the first quarter of 2006 compared to 2005. The increase in production volumes primarily reflects an increase in the number of producing wells, primarily in the Piceance basin.

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 44 percent of domestic production in the first quarter of 2006 was hedged in NYMEX and basis fixed price contracts at a weighted average price of $3.80 per Mcfe at a basin level compared to 53 percent hedged at a weighted average price of $3.95 per Mcfe in 2005. In addition, approximately 17 percent of domestic production was hedged in the following collar agreements for the first quarter of 2006:

- NYMEX collar agreement for approximately 50 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 first quarter of 2005, approximately nine percent of domestic production was hedged in a NYMEX collar agreement for approximately 50 MMcfe per day at a floor price of $7.50 per Mcfe and a ceiling price of $10.49 per Mcfe.

These 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 parties. Hedging decisions are made considering our overall commodity risk exposure and are not executed independently by Exploration & Production.

Total *costs and expenses* increased $65 million, primarily due to the following:

- $15 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;

- $6 million higher lease operating expense from the increased number of producing wells and generally higher industry costs;

- $11 million higher operating taxes primarily due to increased market prices and production volumes sold;

- $4 million higher exploration expenses primarily due to increased geophysical seismic data purchased in the Fort Worth basin;

$5 million higher selling, general, and administrative expenses primarily due to increased staffing in support of increased drilling and operational activity and higher compensation;

$13 million higher gas management expenses, offset in *segment revenues,* which are associated with higher revenues from gas management activities.

Total *costs and expenses* also increased due to the absence in the first quarter of 2006 of a $7.9 million gain on the sale of an undeveloped leasehold position in Colorado in the first quarter of 2005.

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Management s Discussion & Analysis (Continued)

The $43.9 million increase in s*egment profit* is primarily due to increased revenues from higher volumes, higher net realized average prices, and gains from hedge ineffectiveness, partially offset by higher expenses as discussed previously. *Segment profit* also includes a $7 million increase in our international operations reflecting higher revenue and equity earnings resulting from higher net realized oil and gas prices and increased production volumes, primarily from our Apco Argentina operations.

Gas Pipeline

Overview of Three Months Ended March 31, 2006

Gulfstream

In March 2006, Gulfstream announced a new long-term agreement with a Florida utility company. As a result, the pipeline s initial mainline capacity is now fully subscribed 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.

Outlook for the Remainder of 2006

Filing of rate cases

During 2006, we will be focused on successfully filing rate cases for both Transco and Northwest Pipeline subsidiaries which are expected to result in new transportation and storage rates. The anticipated filing date for both pipelines is the third quarter of 2006 with the new rates becoming effective 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, which will replace most of the capacity previously served by 268 miles of 26-inch pipeline in the Washington state area. The estimated cost of the project is $333 million, with an anticipated in-service date of November 1, 2006.

Parachute Lateral project

In January 2006, we filed an application with the FERC to construct a 38-mile expansion that would provide additional natural gas transportation capacity in northwest Colorado. The planned expansion would increase capacity by 450,000 Dth per day through the 30-inch diameter line and is estimated to cost $55 million. The expansion is expected to be in service by January 2007.

Period-Over-Period Results

	Three months ended March 31,	
	2006	2005
	(Millions)	
Segment revenues	$ 334.0	$ 335.3
Segment profit	$ 134.7	$ 167.4

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Management s Discussion & Analysis (Continued)

Three months ended March 31, 2006 vs. three months ended March 31, 2005

Costs and operating expenses increased $17 million, or 10 percent, due primarily to higher operating and maintenance expenses, fuel costs, operating taxes, and the absence of a $7.5 million credit to expense recorded in 2005 related to corrections of the carrying value of certain liabilities. These liabilities had been recorded in prior periods and were no longer required based on a review by management.

SG&A expenses increased $12 million, or 67 percent, due primarily to $5.6 million of cost reductions in 2005 related to corrections of the carrying value of certain liabilities that were recorded in prior periods and were no longer required based on a review by management. Also contributing to the increased expenses were higher staffing and overhead costs.

Our management concluded that the effects of the corrections of the carrying values of certain liabilities that are 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 $32.7 million, or 20 percent, decrease in *segment profit* is due to the absence in 2006 of $13.1 million of adjustments related to the reversal of liabilities in 2005 (noted above), higher operating and maintenance expenses, and lower equity earnings due to the absence of a $4.6 million construction completion fee recognized in 2005 related to Gulfstream. We recognized $2 million of income in 2006 associated with favorable litigation resolution which partially offsets the decreases and is included in *other income net* within *segment profit*.

Midstream Gas & Liquids

Overview of Three Months Ended March 31, 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. to acquire a 25.1 percent interest in Four Corners gathering and processing business

We have entered into an agreement with Williams Partners L.P. for its acquisition of a 25.1 percent interest in Williams Four Corners, LLC, which will own our gathering and processing assets in the Four Corners area, for $360 million. Williams Partners L.P. plans to finance its payment of the cash purchase price through a combination of debt and equity, as detailed in its registration statement on Form S-1 filed with the Securities and Exchange Commission on April 7, 2006. The closing of the transaction is subject to the satisfaction of a number of conditions, including the ability of Williams Partners L.P. to obtain financing and the receipt of all necessary consents. Closing is expected to occur in the second quarter of 2006. The debt issued by Williams Partners L.P. will be reported as a component of our consolidated debt balances.

Gulf Coast operations return to normal operations 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. While some smaller production areas remain at below-normal levels, overall product flows have returned to pre-hurricane levels.

Expansion efforts in growth areas

Consistent with our strategy, we continued to expand our Midstream operations where we have large scale assets in growth basins. The first quarter of 2006 represented our first full quarter of serving the production volumes from the Triton and Goldfinger fields in the deepwater Gulf of Mexico resulting in $11 million in incremental revenues to our Devils Tower facilities. In the first quarter, construction began 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,

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Management s Discussion & Analysis (Continued)
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 second quarter of 2007 to begin processing gas from the Pinedale Anticline field.

Favorable commodity price margins

The actual realized natural gas liquids (NGL) per unit margins at our processing plants exceeded Midstream s historical five-year annual average for the last seven 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 is realized at our Western United States gas processing plants, which benefit from lower regional market natural gas prices. In the first quarter of 2006, NGL production rebounded from the previous quarter s level in response to improved gas processing spreads as crude prices increased and natural gas prices decreased.

Outlook for the Remainder of 2006

The following factors could impact our business in the remaining three quarters of 2006 and beyond.

As evidenced in recent years, natural gas and crude oil markets are highly volatile despite above average margins at our gas processing plants in recent years. Although NGL margins earned at our gas processing plants in the last seven quarters were above the five-year average, we expect unit margins in 2006 to trend downward towards historical averages. As part of our efforts to manage commodity price risks on an enterprise basis, we have initiated the use of commodity hedging strategies.

Gathering and processing volumes 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.

In 2006, we will continue to invest in facilities in the growth basins in which we provide services. The latest expansion of our Wamsutter gathering system is scheduled to be operational during the second quarter of 2006.

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.

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Management s Discussion & Analysis (Continued)

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 will impact revenues, it will 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. We also expect property insurance costs to increase for these deepwater assets.

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.

Period-Over-Period Results

	Three months ended March 31,	
	2006	2005
	(Millions)	
Segment revenues	$ 979.4	$ 807.0
Segment profit (loss)		
Domestic gathering & processing	$ 123.4	$ 100.2
Venezuela	35.5	22.0
Other	7.5	22.0
Unallocated general and administrative expense	(14.9)	(15.6)
Total	$ 151.5	$ 128.6

In order to provide additional clarity, our management 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 March 31, 2006 vs. three months ended March 31, 2005

The $172.4 million increase in Midstream s *revenues* is largely due to $113 million in higher crude marketing revenues as a result additional production coming on-line to a deepwater pipeline in November 2005 while the marketing of NGLs and olefins increased $52 million as a result of both higher prices and higher volumes. All of these variances are offset by similar increases in costs. These increases are partially offset by a $26 million reduction in NGL revenues with a corresponding $26 million reduction in costs of goods sold due to a change in classification of NGL transportation and fractionation expenses. The remaining increase is largely due to $19 million in higher revenues resulting from higher production handling volumes and $10 million in higher gathering and processing and other service revenues.

Costs and operating expenses increased $172 million primarily as a result of $113 million in higher crude and $52 million in higher NGL and olefins marketing purchases partially offset by the above-noted $26 million impact of reporting of NGL transportation and fractionation expenses. In addition, operating expenses increased $15 million due to higher maintenance expenses, system losses and depreciation expense. Olefins cost of goods sold also increased $14 million mostly due to higher feedstock prices.

The $22.9 million increase in Midstream *segment profit* is primarily due to higher net revenues from our gathering and processing facilities and settlement of an international contract dispute, partially offset by lower net olefins and marketing margins and higher operating costs. A more detailed analysis of the *segment profit* of Midstream s various operations is presented as follows.

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Management s Discussion & Analysis (Continued)

Domestic gathering & processing

The $23.2 million increase in *domestic gathering and processing segment profit* includes a $17 million increase in the Gulf Coast region and a $6 million increase in the West region.

The $17 million increase in the Gulf Coast region s *segment profit* is primarily a result of higher volumes from our deepwater facilities partially offset by higher expenses. The significant components of this increase include the following:

Fee revenues from our deepwater assets increased $19 million as a result of $11 million in higher volumes mostly due to new production flows from the Triton and Goldfinger fields, $3 million in higher resident production and $5 million in higher Devils Tower unit-of-production rates recognized as a result of a new reserve study.

Operating expenses increased $4 million as a result of $2 million in higher maintenance expense mostly related to our on-shore gathering systems and $2 million in higher depreciation expense on our deepwater assets.

The $6 million increase in our West region s *segment profit* primarily results from higher gathering and processing fee revenues, higher net product margins, and a gain on an asset sale which were partially offset by higher operating expenses. The significant drivers to these items are as follows:

Net revenues from our gathering and processing business increased $11 million primarily as a result of a $7 million increase in our fee revenues due to higher average per-unit gathering and processing rates. A portion of this increase is also due to the increase in volumes subject to fee-based processing contracts. In addition, net revenues related to the production of condensate and liquefied natural gas increased $3 million due in part to higher commodity prices.

Other income net is $4 million favorable due a first quarter 2006 gain on sale of idle gas treating equipment.

Operating expenses were unfavorable by $10 million largely due to $8 million in higher maintenance expenses in part due to higher leased compression costs and turbine overhauls. In addition, net system product losses were $8 million unfavorable as a result of higher loss volumes coupled with higher gas prices in the first quarter of 2006. These unfavorable items were partially offset by $6 million in lower costs in part due to higher customer gathering fuel reimbursements and other expenses impacted by natural gas prices.

Venezuela

Segment profit for our Venezuela assets increased $13.5 million and includes $9 million resulting from a settlement of an international contract dispute and higher revenues due to higher natural gas volumes and prices at our compression facility.

Other

The $14.5 million decrease in *segment profit* of our other operations is a result of $12 million in lower olefins unit margins and a $9 million reduction in value of NGL pipeline line fill inventory due to falling unit prices. These decreases were partially offset by an approximately $4 million favorable transportation settlement and $3 million in higher earnings from our equity investment in Discovery Producer Services, L.L.C.

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Management s Discussion & Analysis (Continued)

Power

Overview of Three Months Ended March 31, 2006

Power s comparative operating results for the first three months of 2006 were significantly influenced by a decrease in forward natural gas prices against a net short derivative position, which caused net forward unrealized mark-to-market gains. These gains were partially offset by a decrease in forward power prices against a net long derivative position, which caused net forward unrealized mark-to-market losses. Power s results for the first three months of 2006 also reflect the combined impact of increased natural gas and power prices on its nonderivative tolling contracts. Although the average price of power increased, there was a greater increase in the average purchase price of natural gas, which is used to generate power. The continued impact of Hurricane Katrina and increased oil prices primarily affected the prices of natural gas and power. The narrowing of the margin between power and natural gas prices resulted in an accrual gross margin loss (realized costs in excess of realized revenue) on certain tolling contracts. The chart below illustrates the impact of the unrealized mark-to-market gain and accrual gross margin loss on Power s total gross margin (revenue less cost of sales). The below chart does not reflect, however, cash flows that Power realized in the first three months of 2006 from hedges for which mark-to-market gains or losses had been previously recognized.

In the first three 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.

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.

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Management s Discussion & Analysis (Continued)

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 being designated 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, to the extent that future earnings reflect losses from underlying transactions, such as natural gas purchases and power sales associated with tolling transactions, that have been hedged by the derivatives, the corresponding offsetting gains from the hedges have already been recognized in prior periods under mark-to-market accounting. However, cash flows from Power s portfolio continue to reflect the net amount from both the hedged transactions and the hedges.

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 are held for trading purposes;

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.

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 also result in future operating profits or losses as a result of the volatile nature of energy commodity markets.

Period-Over-Period Results

	Three months ended March 31,	
	2006	**2005**
	(Millions)	
Realized revenues	$ 2,010.2	$ 1,843.8
Net forward unrealized mark-to-market gains	43.0	221.1
Segment revenues	2,053.2	2,064.9
Cost of sales	2,076.7	1,925.0
Gross margin	(23.5)	139.9
Operating expenses	5.4	5.3
Selling, general and administrative expenses	(4.5)	16.0
Other (income) expense net	(1.9)	4.5
Segment profit (loss)	$ (22.5)	$ 114.1

Three months ended March 31, 2006 vs. three months ended March 31, 2005

The $166.4 million increase in *realized revenues* is primarily due to an increase in 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 increased primarily due to a 26 percent increase in average natural gas sales prices and a 13 percent increase in average power sales prices. The effects of Hurricane Katrina on supply and other global economic factors related to crude oil supply and demand continue to impact the increased price of natural gas. This increase in gas prices, coupled with an increase in coal prices, both contributed to increased power prices. A 22 percent decrease in power sales volumes partially offsets the increase in prices. Power sales volumes decreased because Power did not replace certain long-term physical contracts that expired or were terminated.

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. A change in the position of our natural gas and power derivative portfolio primarily caused the $178.1 million decrease in *forward unrealized mark-to-market gains.*

Management s Discussion & Analysis (Continued)

Our portfolio of natural gas derivative contracts not designated as cash flow hedges changed from a significant net purchase position in the first quarter of 2005 to a much smaller net sale position in the first quarter of 2006. Forward natural gas prices increased in first-quarter 2005, resulting in a gain on our net forward natural gas purchase position. Forward natural gas prices decreased in first-quarter 2006, also resulting in a gain on our net forward natural gas sales position. Though the price changes were similar, the 2006 gain was smaller than the 2005 gain because of the smaller size of the position. In contrast to natural gas, our portfolio of power derivative contracts not designated as cash flow hedges changed from a relatively small net sale position to a larger net purchase position. A first-quarter 2005 increase in forward power prices caused losses on the net forward power sales position, while a first-quarter 2006 decrease in forward power prices caused a greater loss on the larger position of net forward power purchase contracts.

A $45 million increase in the gains from ineffectiveness of cash flow hedges partially offsets the decrease in *net forward unrealized mark-to-market gains.* A greater change in the locational price difference of the natural gas hedges and the hedged items in 2006 than in 2005 primarily caused the increase in ineffectiveness. Also in first-quarter 2005, Power recognized losses of $6.8 million representing a correction of unrealized losses associated with a prior year. Our management concluded that the effects of this correction are not material to prior periods, 2005 results, or our trend of earnings.

The $151.7 million increase in Power s *cost of sales* is primarily due to an increase in power and natural gas costs. Power and natural gas costs increased primarily due to a 35 percent increase in average power purchase prices and a 26 percent increase in average natural gas purchase prices, partially offset by a 23 percent decrease in power purchase volumes. The continued impact of Hurricane Katrina on natural gas supply coupled with increased oil prices, primarily contributed to the increase in costs.

The decrease in *SG&A expenses* is due primarily to a $23.7 million gain from the sale of certain Enron receivables to a third party. This gain more than offset all of Power s other SG&A expenses in first-quarter 2006.

Other (income) expense net in first-quarter 2005 includes a $4.6 million accrual for a regulatory settlement.

A change in the position of our derivative portfolio not designated as cash flow hedges primarily caused the $136.6 million change from a *segment profit* to a *segment loss.* The $45 million increase in gains from ineffectiveness and the $23.7 million reduction in the allowance for bad debts partially offset the unfavorable change in *segment profit (loss).*

Other

Outlook for the Remainder of 2006

The management of Longhorn is currently negotiating a purchase and sale agreement for Longhorn. We expect to receive full payment of the $10 million secured bridge loan that we provided Longhorn during 2005 from the proceeds of such a sale. We continue to receive payments associated with the 2005 transfer of the Longhorn operating agreement to a third party. These payments totaled approximately $0.9 million during the first quarter of 2006. Any ongoing payments received or through monetization of the contract will be recognized as income when received.

Period-Over-Period Results

	Three months ended March 31, 2006	2005
	(Millions)	
Segment revenues	$ 6.9	$ 7.0
Segment profit (loss)	$ 1.0	$ (4.1)

Other *segment profit* for 2006 is due primarily to the operating agreement payments discussed above. Other *segment loss* for 2005 includes $5.5 million of equity losses related to our investment in Longhorn. As a result of our full impairment of our equity investment in Longhorn during the fourth quarter of 2005, we are no longer recognizing equity losses associated with this investment.

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Management s Discussion & 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 March 31, 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
$13	$(1)	$1	$	$	$13

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 on an economic basis forecasted transactions. We have designated certain of these contracts as cash flow hedges of Power s forecasted purchases of gas, and purchases and sales of power related to its long-term structured contracts and owned generation, and Exploration & Production s forecasted sales of natural gas production. 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 March 31, 2006, for both the Power and Exploration & Production businesses. Of the total fair value of nontrading derivatives, SFAS 133 cash flow hedges had a net asset value of $274 million as of March 31, 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
$(30)	$167	$219	$2	$	$358

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 March 31, 2006, we held collateral support, including letters of credit, of $847 million.

The gross credit exposure from our derivative contracts as of March 31, 2006, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 253.8	$ 265.0
Energy marketers and traders	2,208.5	4,773.6
Financial institutions	2,088.4	2,088.4
Other	23.4	23.6

	$ 4,574.1	7,150.6
Credit reserves		(25.5)
Gross credit exposure from derivatives		$ 7,125.1

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Management s Discussion & Analysis (Continued)

We assess our credit exposure on a net basis. The net credit exposure from our derivatives as of March 31, 2006, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 192.2	$ 194.5
Energy marketers and traders	387.0	781.0
Financial institutions	298.1	298.1
Other	20.7	20.7
	$ 898.0	1,294.3
Credit reserves		(25.5)
Net credit exposure from derivatives		$ 1,268.8

(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 & 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 and near term scheduled debt payments. 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 will construct an 80 mile pipeline loop, which will replace most of the capacity previously served by 268 miles of pipeline in the Washington state area.

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. We received the first four rigs through April 2006 and have begun drilling.

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 billion to $2.2 billion in 2006, with approximately $1.5 billion to $1.7 billion to be incurred over the remainder of the year. Of the total estimated capital expenditures for 2006, $950 million to $1.1 billion is for capital expenditures at Exploration & Production. Also within the total estimated expenditures for 2006 is approximately $616 million to $681 million for maintenance-related projects at Gas Pipeline, including pipeline replacement and Clean Air Act compliance.

In April 2006, Transco issued $200 million aggregate principal amount of 6.4 percent senior notes due 2016 to certain institutional investors in a private debt placement. Transco intends to use the net proceeds for general corporate purposes and the funding of capital expenditures.

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. We anticipate refinancing a portion of this issue at the corporate parent level on an unsecured basis later this year.

In May 2006, we replaced our $1.275 billion secured credit facility with a $1.5 billion unsecured revolving credit facility. The new facility contains similar terms and covenants as the secured facility.

We have entered into an agreement with Williams Partners L.P. for its acquisition of a 25.1 percent interest in Williams Four Corners, LLC, which will own our gathering and processing assets in the Four Corners area, for $360 million. Williams Partners L.P. plans to finance its payment of the cash purchase price through a combination of debt and equity, as detailed in its registration statement on Form S-1 filed with the Securities and Exchange Commission on April 7, 2006. The closing of the transaction is subject to the satisfaction of a number of conditions, including the ability of Williams Partners L.P. to obtain financing and the receipt of all necessary consents. Closing is expected to occur in the second quarter of 2006. The debt issued by Williams Partners L.P. will be reported as a component of our consolidated debt balances.

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Management s Discussion & Analysis (Continued)

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 301 MMcfe per day of its remaining expected 2006 production. Power has entered into fixed forward 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.

  For the remainder of 2006, we estimate our exposure to additional margin requirements to be no more than $667 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).

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.

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.

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Management s Discussion & Analysis (Continued)

Available Liquidity

	March 31, 2006 (Millions)
Cash and cash equivalents*	$ 1,115.0
Auction rate securities and other liquid securities	183.9
Available capacity under our four unsecured revolving and letter of credit facilities totaling $1.2 billion	189.8
Available capacity under our $1.275 billion secured revolving and letter of credit facility**	1,159.7
	$ 2,648.4

Additional Liquidity

Shelf registration for a variety of debt and equity securities	$ 2,200.0
Shelf registration for debt only available to Northwest Pipeline and Transco***	$ 350.0

* *Cash and cash equivalents* includes $129.1 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.

** This facility is secured by the common stock of Transco and 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. See previous discussion of changes to this credit facility subsequent to March 31, 2006.

*** The ability of Northwest Pipeline to utilize these registration statements for debt securities is restricted by certain covenants of its debt agreements. So long as our credit rating is below investment grade, Northwest Pipeline and Transco can only use their shelf registration statements to issue debt if such debt is guaranteed by us.

Sources (Uses) of Cash

	Three months ended March 31, 2006	Three months ended March 31, 2005
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 164.7	$ 304.4
Financing activities	(155.8)	58.8
Investing activities	(491.1)	(83.2)
Increase (decrease) in cash and cash equivalents	$ (482.2)	$ 280.0

Operating activities

Our *net cash provided by operating activities* for the three months ended March 31, 2006 decreased from the same period in 2005. The primary driver in the decrease in *net cash provided by operating activities* is an increase in net cash outflows from *margin deposits and customer margin deposits payable* due primarily to natural gas price decreases on marginal positions.

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

Dividends paid on common stock are currently $.075 per common share on a quarterly basis and totaled $44.6 million for the three months ended March 31, 2006. For the three months ended March 31, 2005, dividends paid on common stock were $.05 per share on a quarterly basis and totaled $28.5 million.

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Management s Discussion & Analysis (Continued)

Investing activities

During the first quarter of 2006, capital expenditures totaled $468.3 million and were primarily related to Exploration & Production s increased drilling activity and drilling costs, mostly in the Piceance basin.

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.

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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 three months of 2006.

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 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 $4 million at March 31, 2006 and December 31, 2005.

Nontrading

Our nontrading portfolio consists of 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
Power	Natural gas purchases and sales Electricity purchases and sales

The value at risk for contracts held for nontrading purposes was $6 million at March 31, 2006, and $17 million at December 31, 2005. Certain of the contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS 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.

First-Quarter 2006 Changes in Internal Controls Over Financial Reporting

There have been no changes during first-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 have recently occurred 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 10.1 Form of 2006 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our Form 8-K filed March 7, 2006).

Exhibit 10.2 Form of 2006 Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our Form 8-K filed March 7, 2006).

Exhibit 10.3 Form of 2006 Performance-Based Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.3 to our Form 8-K filed March 7, 2006).

Exhibit 10.4 Credit Agreement, dated as of May 1, 2006, among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, and Williams Partners L.P., as Borrowers, and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.1 to our Form 8-K filed May 1, 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)

May 4, 2006