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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2005

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 ☑ No o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes ☑ No o

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 July 31, 2005
Common Stock, $1 par value	572,181,101 Shares

The Williams Companies, Inc.
Index

	Page
Part I. Financial Information	
Item 1. Financial Statements	
Consolidated Statement of Operations — Three and Six Months Ended June 30, 2005 and 2004	3
Consolidated Balance Sheet — June 30, 2005 and December 31, 2004	4
Consolidated Statement of Cash Flows — Six Months Ended June 30, 2005 and 2004	5

Notes to Consolidated Financial Statements	6
Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations	26
Item 3. Quantitative and Qualitative Disclosures about Market Risk	54
Item 4. Controls and Procedures	56
Part II. Other Information	
Item 1. Legal Proceedings	57
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds	57
Item 4. Submission of Matters to a Vote of Security Holders	57
Item 5. Other Information	57
Item 6. Exhibits	58

Computation of Ratio of Earnings
Certification of CEO Pursuant to Section 302
Certification of CFO Pursuant to Section 302
Certification of CEO and CFO Pursuant to Section 906

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 words such as "anticipates," "believes," "expects," "planned," "scheduled," "could," "continues," "estimates," "forecasts," "might," "potential," "projects" or similar 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 may cause future results to be materially different from the results 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 2004 Form 10-K.

Table of Contents

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

(Dollars in millions, except per-share amounts)	Three months ended June 30, 2005	Three months ended June 30, 2004*	Six months ended June 30, 2005	Six months ended June 30, 2004*
Revenues:				
Power	$ 1,999.4	$ 2,333.2	$ 4,064.3	$ 4,629.6
Gas Pipeline	357.0	331.0	692.3	690.0
Exploration & Production	281.5	189.0	530.5	354.2
Midstream Gas & Liquids	780.1	633.7	1,587.1	1,265.5
Other	6.1	7.0	13.1	19.6
Intercompany eliminations	(552.9)	(442.0)	(1,062.1)	(837.0)
Total revenues	2,871.2	3,051.9	5,825.2	6,121.9
Segment costs and expenses:				
Costs and operating expenses	2,491.6	2,661.4	4,881.9	5,352.3
Selling, general and administrative expenses	62.7	82.8	136.2	168.3
Other expense – net	21.9	23.2	20.1	31.5
Total segment costs and expenses	2,576.2	2,767.4	5,038.2	5,552.1
General corporate expenses	35.5	28.4	63.5	60.4
Operating income (loss):				
Power	(75.9)	24.2	37.1	13.1
Gas Pipeline	156.6	128.3	312.6	272.2
Exploration & Production	114.7	40.1	214.9	88.7
Midstream Gas & Liquids	104.3	95.1	225.8	201.2
Other	(4.7)	(3.2)	(3.4)	(5.4)
General corporate expenses	(35.5)	(28.4)	(63.5)	(60.4)
Total operating income	259.5	256.1	723.5	509.4
Interest accrued	(164.6)	(222.3)	(329.3)	(465.6)
Interest capitalized	1.4	.7	2.5	4.7
Interest rate swap income (loss)	—	6.8	—	(1.3)
Investing income (loss)	(17.2)	11.6	13.8	22.0
Early debt retirement costs	—	(96.8)	—	(97.3)
Minority interest in income of consolidated subsidiaries	(4.8)	(6.0)	(10.0)	(10.8)
Other income – net	8.1	13.6	13.6	14.9
Income (loss) from continuing operations before income taxes	82.4	(36.3)	414.1	(24.0)
Provision (benefit) for income taxes	41.7	(17.8)	171.2	(5.5)
Income (loss) from continuing operations	40.7	(18.5)	242.9	(18.5)
Income (loss) from discontinued operations	.6	.3	(.5)	10.2
Net income (loss)	$ 41.3	$ (18.2)	$ 242.4	$ (8.3)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ .07	$ (.03)	$ .43	$ (.04)
Income (loss) from discontinued operations	—	—	—	.02
Net income (loss)	$ .07	$ (.03)	$ .43	$ (.02)
Weighted-average shares (thousands)	571,208	521,698	567,841	520,592
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ .07	$ (.03)	$ .41	$ (.04)
Income (loss) from discontinued operations	—	—	—	.02
Net income (loss)	$ .07	$ (.03)	$ .41	$ (.02)
Weighted-average shares (thousands)	578,902	521,698	602,956	520,592
Cash dividends per common share	$ .05	$ .01	$ .10	$ .02

* Certain amounts have been reclassified as described in Note 2 of Notes to Consolidated Financial Statements.

See accompanying notes.

Table of Contents

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

(Dollars in millions, except per-share amounts)	June 30, 2005	December 31, 2004*
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,297.2	$ 930.0
Restricted cash	65.3	77.4
Accounts and notes receivable less allowance of $92.7 ($98.8 in 2004)	1,227.3	1,422.8
Inventories	259.5	261.1
Derivative assets	3,496.4	2,961.0
Margin deposits	166.5	131.7
Assets of discontinued operations	12.8	13.6
Deferred income taxes	11.3	89.0
Other current assets and deferred charges	236.3	157.0
Total current assets	6,772.6	6,043.6
Restricted cash	35.3	35.3
Investments	1,285.1	1,316.2
Property, plant and equipment, at cost	16,837.6	16,452.8
Less accumulated depreciation and depletion	(4,858.5)	(4,566.0)
Property, plant and equipment — net	11,979.1	11,886.8
Derivative assets	4,577.5	3,025.3
Goodwill	1,014.5	1,014.5
Other assets and deferred charges	735.6	671.3
Total assets	$26,399.7	$23,993.0
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current liabilities:		
Accounts payable	$ 944.8	$ 1,043.2
Accrued liabilities	941.8	974.0
Customer margin deposits payable	127.1	17.7
Deferred income tax	98.6	—
Liabilities of discontinued operations	1.3	1.6
Derivative liabilities	3,510.3	2,859.3
Long-term debt due within one year	98.6	250.1
Total current liabilities	5,722.5	5,145.9
Long-term debt	7,645.7	7,711.9
Deferred income taxes	2,377.4	2,470.1
Derivative liabilities	4,295.8	2,735.7
Other liabilities and deferred income	909.3	873.8
Contingent liabilities and commitments (Note 12)		
Minority interests in consolidated subsidiaries	95.4	99.7
Stockholders’ equity:		
Common stock, $1 per share par value, 960 million shares authorized, 577.2 million issued in 2005, 563.8 million issued in 2004	577.2	563.8
Capital in excess of par value	6,295.8	6,005.9
Accumulated deficit	(1,121.1)	(1,306.5)
Accumulated other comprehensive loss	(342.2)	(244.2)
Other	(14.9)	(21.9)
	5,394.8	4,997.1
Less treasury stock (at cost), 5.7 million shares of common stock in 2005 and 2004	(41.2)	(41.2)
Total stockholders’ equity	5,353.6	4,955.9
Total liabilities and stockholders’ equity	$26,399.7	$23,993.0

* Certain amounts have been reclassified as described in Note 2 of Notes to Consolidated Financial Statements.

See accompanying notes.

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

	Six months ended June 30, 2005	2004*
	(Millions)	
OPERATING ACTIVITIES:		
Income (loss) from continuing operations	$ 242.9	$ (18.5)
Adjustments to reconcile to cash provided by operations:		
Depreciation, depletion and amortization	356.3	328.5
Provision (benefit) for deferred income taxes	149.6	(18.9)
Provision for loss on investments, property and other assets	53.5	30.0
Net gain on disposition of assets	(20.7)	(2.0)
Minority interest in income of consolidated subsidiaries	10.0	10.8
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	172.7	150.0
Inventories	1.6	(12.5)
Margin deposits and customer margin deposits payable	74.6	146.0
Other current assets and deferred charges	(7.2)	108.7
Accounts payable	(126.8)	(138.4)
Accrued liabilities	(68.9)	(158.4)
Changes in current and noncurrent derivative assets and liabilities	(27.3)	77.7
Other, including changes in noncurrent assets and liabilities	(17.0)	109.5
Net cash provided by operating activities of continuing operations	793.3	612.5
Net cash provided by operating activities of discontinued operations	—	2.6
Net cash provided by operating activities	793.3	615.1
FINANCING ACTIVITIES:		
Payments of long-term debt	(220.7)	(2,217.0)
Payments of notes payable	—	(3.3)
Proceeds from issuance of common stock	296.6	11.9
Fees paid to amend credit facilities	(19.2)	—
Dividends paid	(57.1)	(10.4)
Payments of debt issuance costs	—	(20.4)
Premiums paid on tender offer and early debt retirement	—	(79.5)
Dividends paid to minority interests	(14.3)	(5.2)
Changes in restricted cash	21.2	16.9
Changes in cash overdrafts	26.9	(27.4)
Other — net	(.2)	(3.1)
Net cash provided (used) by financing activities of continuing operations	33.2	(2,337.5)
Net cash used by financing activities of discontinued operations	—	(1.2)
Net cash provided (used) by financing activities	33.2	(2,338.7)
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(516.6)	(329.0)
Proceeds from dispositions	9.6	3.0
Contract termination payment	87.9	—
Purchases of investments/advances to affiliates	(81.9)	(1.6)
Purchases of auction rate securities	(155.3)	—
Purchases of restricted investments	—	(471.8)
Proceeds from sales of businesses	1.3	306.0
Proceeds from sales of auction rate securities	100.3	—
Proceeds from sale of restricted investments	—	851.4
Proceeds received on sale of note from WilTel	54.7	—
Proceeds from dispositions of investments and other assets	35.4	85.2
Other — net	5.3	(6.7)
Net cash provided (used) by investing activities of continuing operations	(459.3)	436.5
Net cash used by investing activities of discontinued operations	—	(.8)
Net cash provided (used) by investing activities	(459.3)	435.7
Increase (decrease) in cash and cash equivalents	367.2	(1,287.9)
Cash and cash equivalents at beginning of period	930.0	2,318.2
Cash and cash equivalents at end of period	$1,297.2	$ 1,030.3

* Certain amounts have been reclassified as described in Note 2 of Notes to Consolidated Financial Statements.

See accompanying notes.

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

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 June 30, 2005, and results of operations for the three and six months ended June 30, 2005 and 2004 and cash flows for the six months ended June 30, 2005 and 2004.

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.

2. Basis of presentation

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the accompanying consolidated financial statements and notes reflect the results of operations, financial position and cash flows of the following components as discontinued operations (see Note 5):

- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment; and
- our straddle plants in western Canada, previously part of the Midstream Gas & Liquids (Midstream) segment.

During fourth-quarter 2004, we reclassified the operations of Gulf Liquids New River Project L.L.C. (Gulf Liquids) to continuing operations within our Midstream segment in accordance with Emerging Issues Task Force (EITF) Issue No. 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, in Determining Whether to Report Discontinued Operations'' (EITF 03-13), which was issued in the fourth quarter of 2004. Under the provisions of EITF 03-13, Gulf Liquids activities no longer qualified for reporting as discontinued operations based on management's expectation that we will continue to have significant commercial activity with the disposed entity. The operations of Gulf Liquids were reclassified to continuing operations within our Midstream segment. All periods presented reflect this reclassification.

At March 31, 2005, all of the assets and liabilities of Gulf Liquids, which are not material to our Consolidated Balance Sheet, were classified as held for sale and included in Other current assets and deferred charges and Accrued liabilities. During second-quarter 2005, we decided to retain a portion of the Gulf Liquids operations and reclassified certain of the assets and liabilities from held for sale to held for use. The sale of the remaining assets held for sale closed on July 15, 2005.

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

We have restated all segment information in the Notes to Consolidated Financial Statements for the prior periods presented to reflect the discontinued operations noted above, consistent with the presentation in our 2004 Form 10-K. In addition, certain other amounts have been reclassified to conform to the current classification.

Notes (Continued)

3. Asset sales, impairments and other accruals

Significant gains or losses from asset sales, impairments and other accruals included in Other expense – net within Segment costs and expenses and Investing income (loss) are included in the following tables.

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
	(Millions)		(Millions)	
Other expense – net:				
Power				
Accrual for litigation contingencies	$13.1	$ —	$13.1	$ —
Gas Pipeline				
Write-off of previously-capitalized costs	—	9.0	—	9.0
Exploration & Production				
Loss provision related to an ownership dispute	—	11.3	—	11.3

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
	(Millions)		(Millions)	
Investing income (loss):				
Midstream Gas & Liquids				
Gain on sale of remaining interests in Mid-America Pipeline (MAPL) and Seminole Pipeline (Seminole)	$ 8.6	$ —	$ 8.6	$ —
Other				
Impairment of investment in Longhorn Partners Pipeline L.P. (Longhorn)	(49.1)	(10.8)	(49.1)	(10.8)
Net unreimbursed Longhorn recapitalization advisory fees	—	—	—	(6.5)

The impairment of Longhorn in second-quarter 2005 reflects a reduction of carrying value to management's estimate of fair market value, following a determination that there was an other-than-temporary decline in value. During the second quarter, Longhorn's management determined that continued operation as originally planned is no longer feasible. Based on that assessment, we recorded an impairment of $49.1 million, resulting in a remaining net book value of $51.4 million. We will continue to consider various strategic scenarios and reassess our estimate of fair value in Longhorn following management's finalization of a strategic alternative to the current operating plan, which may result in a significant additional impairment in a future period. We expect a decision on the future operation of Longhorn by the end of 2005.

4. Provision (benefit) for income taxes

The provision (benefit) for income taxes from continuing operations includes:

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
	(Millions)		(Millions)	
Current:				
Federal	$ 3.0	$ (.1)	$ 7.3	$ 3.2
State	2.8	2.6	8.0	4.4
Foreign	5.2	3.3	6.3	5.8
	11.0	5.8	21.6	13.4
Deferred:				
Federal	36.2	(13.2)	139.1	(13.1)
State	.1	(12.7)	16.1	(10.4)
Foreign	(5.6)	2.3	(5.6)	4.6
	30.7	(23.6)	149.6	(18.9)
Total provision (benefit)	$41.7	$(17.8)	$171.2	$ (5.5)

The effective income tax rate for the three months ended June 30, 2005, is greater than the federal statutory rate due primarily to the effect of state income taxes, nondeductible expenses and an accrual for income tax contingencies.

Notes (Continued)

The effective income tax rate for the six months ended June 30, 2005, is greater than the federal statutory rate due primarily to the effect of state income taxes, nondeductible expenses and an accrual for income tax contingencies.

The effective income tax rate benefit for the three months ended June 30, 2004, is greater than the federal statutory rate due primarily to the effect of state income taxes partially offset by net foreign operations.

The effective income tax rate benefit for the six months ended June 30, 2004, is less than the federal statutory rate due primarily to the effect of net foreign operations and an accrual for income tax contingencies, partially offset by the effect of state income taxes.

5. Discontinued operations

The businesses discussed below represent components that have been sold or approved for sale by our Board of Directors as of June 30, 2005, and also meet all requirements to be treated as discontinued operations. Therefore, their results of operations (including any impairments, gains or losses), financial position and cash flows have been reflected in the consolidated financial statements and notes as discontinued operations.

Discontinued operations did not generate any revenues for the three and six months ended June 30, 2005. Discontinued operations included revenues of $42.2 million for the three months ended June 30, 2004, and $332 million for the six months ended June 30, 2004.

2004 completed transactions

Canadian straddle plants

During the third quarter of 2004, we completed the sale of the Canadian straddle plants for approximately $544 million. The operations were part of the Midstream segment.

Alaska refining, retail and pipeline operations

On March 31, 2004, we completed the sale of our Alaska refinery, retail and pipeline operations for approximately $304 million. We received $279 million in cash at the time of the sale and $25 million in cash during the second quarter of 2004. We recognized a $3.6 million pre-tax gain on the sale. These operations were part of the previously reported Petroleum Services segment.

Notes (Continued)

6. Earnings (loss) per share from continuing operations

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

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
	(Dollars in millions, except per-share amounts; shares in thousands)		(Dollars in millions, except per-share amounts; shares in thousands)	
Income (loss) from continuing operations available to common stockholders for basic and diluted earnings per share (1)	$ 40.7	$ (18.5)	$ 242.9	$ (18.5)
Basic weighted-average shares (2)	571,208	521,698	567,841	520,592
Effect of dilutive securities:				
Unvested deferred shares (3)	2,980	—	2,774	—
Stock options	4,714	—	4,793	—
Convertible debentures	—	—	27,548	—
Diluted weighted-average shares	578,902	521,698	602,956	520,592
Earnings (loss) per share from continuing operations:				
Basic	$ .07	$ (.03)	$ .43	$ (.04)
Diluted	$ .07	$ (.03)	$ .41	$ (.04)

(1) Six months ended June 30, 2005, includes $5.1 million of interest expense, net of tax, associated with the convertible debentures. This amount has been added back to calculate diluted earning per share.

(2) In February 2005 and October 2004, we issued 10.9 million and 33.1 million shares, respectively, of common stock associated with our FELINE PACS units (see Note 11).

(3) The unvested deferred shares outstanding at June 30, 2005 will vest over the period from July 2005 to January 2010.

For the three and six months ended June 30, 2004, approximately 2.8 million and 2.6 million weighted-average unvested deferred shares, respectively, and approximately 3.5 million and 3.7 million weighted-average stock options, respectively, have been excluded from the computation of Diluted earnings per common share as their inclusion would be antidilutive.

For the three months ended June 30, 2005, and the three and six months ended June 30, 2004, approximately 27.5 million weighted-average shares related to the assumed conversion of convertible debentures, as well as the related interest, have been excluded from the computation of Diluted earnings per common share. Inclusion of these shares would have been antidilutive. If no other components used to calculate Diluted earnings per common share change, we estimate the assumed conversion of the convertible debentures would become dilutive and therefore be included in Diluted earnings per common share at an Income from continuing operations applicable to common stock amount of $53.5 million for the three months ended June 30, 2005, and $48.8 million and $97.4 million for the three and six months ended June 30, 2004, respectively.

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

	2005	2004
Options excluded (millions)	8.8	9.4
Weighted-average exercise prices of options excluded	$ 28.31	$ 27.43
Exercise price range of options excluded	$18.15-$42.29	$11.71-$42.29
Second-quarter weighted-average market price	$ 18.12	$ 11.03

Notes (Continued)

7. Employee benefit plans

Net periodic pension and other postretirement benefit (income) expense for the three and six months ended June 30, 2005 and 2004 are as follows:

	Pension Benefits			
	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(Millions)		(Millions)	
Components of net periodic pension (income) expense:				
Service cost	$ 4.7	$ 5.1	$ 10.8	$ 12.1
Interest cost	11.8	10.7	23.8	25.2
Expected return on plan assets	(20.3)	(17.5)	(35.5)	(32.4)
Amortization of prior service cost (credit)	.2	(.1)	(.2)	(.8)
Recognized net actuarial (gain) loss	(13.2)	.9	(10.0)	4.6
Regulatory asset amortization (deferral)	(.9)	(.1)	(.4)	1.0
Settlement/curtailment expense	.7	.1	2.6	.1
Net periodic pension (income) expense	$(17.0)	$ (.9)	$ (8.9)	$ 9.8

	Other Postretirement Benefits			
	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(Millions)		(Millions)	
Components of net periodic postretirement benefit expense:				
Service cost	$ .6	$ .3	$ 1.5	$ 1.8
Interest cost	5.1	5.1	8.8	10.8
Expected return on plan assets	(2.4)	(3.1)	(5.7)	(6.2)
Amortization of transition obligation	—	.7	—	1.3
Amortization of prior service cost (credit)	(2.9)	.1	(4.1)	.3
Recognized net actuarial loss	1.5	—	1.5	—
Regulatory asset amortization	2.2	1.9	3.8	3.5
Net periodic postretirement benefit expense	$ 4.1	$ 5.0	$ 5.8	$11.5

Net periodic pension (income) expense for the three and six months ended June 30, 2005, includes a $17.1 million reduction to expense to record the cumulative impact of a correction of an error determined from 2003 and 2004. The error was associated with our third-party actuarial computation of annual net periodic pension expense which resulted from the identification of errors in certain Transcontinental Gas Pipe Line Corporation (Transco) participant data involving annuity contract information utilized for 2003 and 2004. The adjustment is reflected as $16.1 million within recognized net actuarial (gain) loss and $1.0 million within regulatory asset amortization (deferral).

As of June 30, 2005, we have contributed $29.8 million to our pension plans and $7.6 million to our other postretirement benefit plans. We presently anticipate contributing approximately $28 million more to our pension plans in 2005 for a total of approximately $58 million. We presently anticipate contributing approximately $7 million more to our other postretirement benefit plans in 2005 for a total of approximately $15 million.

In December 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act) was signed into law. The Act introduces a prescription drug benefit under Medicare (Medicare Part D) beginning in 2006 as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Our health care plans for retirees include prescription drug coverage. We amended our health care plans for retirees in the fourth quarter of 2004 to coordinate and pay secondary to any part of Medicare, including prescription drug benefits covered by Medicare Part D. As a result of the amendment, our plans were not actuarially equivalent to Medicare Part D. The amendment decreased our benefit obligation by $75.5 million in 2004. The net reduction to the obligation is being amortized over approximately seven years which is the participants' average remaining years of service to full eligibility for benefits beginning in 2005 and is reflected in the amortization of prior service credit for other postretirement benefits in the previous table for the six months ended June 30, 2005.

Due to anticipated difficulties to administer our plans as previously amended to coordinate and pay secondary to Medicare Part D in 2006, we amended our plans in June 2005 to provide primary prescription drug coverage and apply for the federal subsidy in 2006. As a result of the amendment, our plans are actuarially equivalent to Medicare Part D. The amendment increased our benefit obligation by $51.2 million at June 30, 2005. The increase to the obligation will be amortized over the participants' average remaining years of service to full eligibility for benefits, which is approximately seven years, beginning in the third quarter of 2005. We are continuing to evaluate coordination with Medicare Part D as a strategy to decrease our benefit obligation in the future and will closely monitor the development of systems and capabilities of third-party administrators to coordinate prescription drug benefits with the Centers for Medicare & Medicaid Services.

Notes (Continued)

8. Stock-based compensation

Employee stock-based awards are accounted for under Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Fixed-plan common stock options generally do not result in compensation expense because the exercise price of the stock option equals the market price of the underlying stock on the date of grant. The following table illustrates the effect on net income (loss) and earnings (loss) per share for the three and six months ended June 30, 2005 and 2004 if we had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." We currently calculate fair value using the Black-Scholes pricing model.

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(Millions)		(Millions)	
Net income (loss), as reported	$41.3	$(18.2)	$242.4	$ (8.3)
Add: Stock-based employee compensation expense included in the Consolidated Statement of Operations, net of related tax effects	2.2	1.3	4.0	5.8
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(2.6)	(3.2)	(8.0)	(10.7)
Pro forma net income (loss)	$40.9	$(20.1)	$238.4	$(13.2)
Earnings (loss) per share:				
Basic – as reported	$ .07	$ (.03)	$ .43	$ (.02)
Basic – pro forma	$ .07	$ (.04)	$ .42	$ (.03)
Diluted – as reported	$ .07	$ (.03)	$ .41	$ (.02)
Diluted – pro forma	$ .07	$ (.04)	$ .40	$ (.03)

Since compensation expense for stock options is recognized over the future years' vesting period for pro forma disclosure purposes and additional awards are generally made each year, pro forma amounts may not be representative of future years' amounts.

9. Inventories

Inventories at June 30, 2005 and December 31, 2004 are as follows:

	June 30, 2005	December 31, 2004
	(Millions)	
Natural gas liquids	$ 72.1	$ 63.2
Natural gas in underground storage	115.7	133.1
Materials, supplies and other	71.7	64.8
	$259.5	$261.1

10. Debt and banking arrangements

Revolving credit and letter of credit facilities

In January 2005, we terminated our two existing unsecured bank revolving credit facilities totaling $500 million and replaced them with two new facilities. The new credit facilities contain the same terms as the previous credit agreements, but almost all of the restrictive covenants and events of default were removed or made less restrictive. As a result of the termination and replacement, we paid $17.9 million in fees, which are being amortized over the life of the new facilities. At June 30, 2005, letters of credit totaling $483 million have been issued under these facilities and no revolving credit loans are outstanding.

Notes (Continued)

Under our $1.275 billion secured revolving credit facility, letters of credit totaling $531 million have been issued and no revolving credit loans are outstanding at June 30, 2005. During May 2005, we amended and restated this agreement resulting in certain changes, including the following:

- added Williams Partners L.P. as a borrower for up to $75 million;
- provided our guarantee for the obligations of Williams Partners L.P.;
- released certain Midstream assets held as collateral and replaced them with the common stock of Transco; and
- reduced commitment fees and margins.

Retirements

During January 2005, we retired $200 million of 6.125 percent notes issued January 15, 1998, by Transco, which matured January 15, 2005.

11. Stockholders' equity

In January 2002, we issued $1.1 billion of 6.5 percent notes payable in 2007 that were subject to remarketing in 2004. Each note was bundled with an equity forward contract (together, the FELINE PACS units) and sold in a public offering for $25 per unit. The equity forward contract required the holder of each note to purchase one share of our common stock for $25 three years from issuance of the contract. In the fourth quarter of 2004, we exchanged approximately 33.1 million of the 44 million issued and outstanding FELINE PACS units for one share of our common stock plus $1.47 in cash for each unit. On the February 16, 2005, settlement date of the equity forward contracts, the holders of the remaining 10.9 million equity forward contracts purchased one share of our common stock for $25, resulting in cash proceeds of approximately $273 million and an increase in Capital in excess of par of approximately $262 million.

12. 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 $5 million for potential refund as of June 30, 2005.

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 have been challenged in various proceedings, including those before the Federal Energy Regulatory Commission (FERC). These challenges include 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 have substantially resolved each of these issues. While the Utilities Settlement is final, an aspect of the State Settlement related to civil litigation has been appealed. Certain issues, however, remain open at the FERC and for other non-settling parties, such as the United States Department of Justice (DOJ).

Notes (Continued)

Refund proceedings

Although we have entered into the State Settlement and Utilities Settlement, which resolve the refund issues among the settling parties, we have potential refund exposure to non-settling parties, such as various California end users that have not agreed to opt into 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 non-settling parties. We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable of approximately $30 million at June 30, 2005. 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 at the Ninth Circuit Court of Appeals.

Summer 2002 90-day contracts

On May 2, 2002, PacifiCorp filed a complaint against us with the FERC seeking relief from rates contained in three separate confirmation agreements between PacifiCorp and Power (known as the Summer 2002 90-day contracts). PacifiCorp filed similar complaints against three other suppliers. PacifiCorp alleged that the rates contained in the contracts are unjust and unreasonable. On June 26, 2003, the FERC affirmed the administrative law judge's initial decision dismissing the complaints. PacifiCorp has appealed the FERC's order to the Ninth Circuit Court of Appeals after the FERC denied rehearing of its order on November 10, 2003.

Investigations of alleged market manipulation

As a result of various allegations and FERC orders, in 2002 the FERC initiated investigations of manipulation of the California gas and power markets. As they related to us, these investigations included economic and physical withholding, so-called "Enron Gaming Practices" and gas index manipulation. Each of these FERC investigations of alleged market manipulation was resolved pursuant to the Utilities Settlement that is discussed above in *Refund proceedings.*

As also discussed below in ***Reporting of natural gas-related information to trade publications,*** on November 8, 2002, we received a subpoena from a federal grand jury in northern California seeking documents related to our involvement in California markets. We have completed our response to the subpoena. This subpoena is a part of the broad DOJ investigation regarding gas and power trading.

Long-term contracts

In February 2001, during the height of the California energy crisis, we entered into a long-term power contract with the State of California to assist in stabilizing its market. The State of California later sought to rescind this contract. Following settlement discussions between the State and us on the contract issue as well as other state initiated proceedings and allegations of market manipulation, we entered into the State Settlement that includes renegotiated long-term energy contracts. These contracts are made up of block energy sales, dispatchable products and a gas contract. The State Settlement does not extend to criminal matters or matters of willful fraud, but did resolve civil complaints brought by the California Attorney General against us and the State of California's refund claims that are discussed above. In addition, the State Settlement resolved ongoing investigations by the States of California, Oregon and Washington. Certain private class action and other civil plaintiffs who have initiated class action litigation against us and others in California based on allegations against us with respect to the California energy crisis also executed the State Settlement. On June 29, 2004, the court approved the State Settlement, making it effective as to plaintiffs and terminating the class actions as to us. A limited group did opt out of the State Settlement. An appeal of the approval order is currently pending. Litigation by non-California plaintiffs, or relating to reporting of natural gas information to trade publications, as discussed below, will continue. As of June 30, 2005, pursuant to the terms of the State Settlement, we have transferred ownership of six gas powered electric turbines, have made three payments totaling $87 million to the California Attorney General, and have funded a $15 million fee and expense fund associated with civil actions that are subject to the State Settlement. An additional $60 million, 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. As noted above, on November 8, 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. The DOJ's investigation of us in this matter is continuing, and we are discussing the disposition of this matter with the DOJ. While it is reasonably possible that material penalties could result in addition to amounts accrued at June 30, 2005, a reasonable estimate of such amount cannot be determined at this time. If we are unable to reach a consensual disposition with the DOJ, it is also possible that we will be indicted by the DOJ for alleged violations of the Commodity Exchange Act. In addition, the Commodity Futures Trading Commission (CFTC) has conducted an investigation of us regarding this issue. On July 29, 2003, we reached a settlement with the CFTC in which in exchange for $20 million, the CFTC closed its investigation, and we did not admit or deny allegations that we had engaged in false reporting or attempted manipulation. Civil suits based on allegations of manipulating the gas indices have been brought against us and others. We are currently a defendant in federal court in New York based on an allegation of manipulation of the NYMEX gas market. We are also a defendant in class actions in federal court in Nevada alleging that we manipulated gas prices for direct purchasers of gas in California and in state court in California alleging that we manipulated prices for indirect purchasers of gas in California. Separate cases have also been filed against us in California on behalf of certain individual gas users. We are also a defendant in class action litigation in Tennessee brought on behalf of indirect purchasers of gas in Tennessee. Each of these cases is in the early stages of discovery and limited settlement discussions regarding certain of these matters has occurred.

Investigations related to natural gas storage inventory

We responded to a subpoena from the CFTC and inquiries from the FERC related to investigations involving natural gas storage inventory issues. Through some of our subsidiaries, we own and operate natural gas storage facilities. On August 30, 2004, the CFTC announced that it had concluded its investigation. The FERC inquiries related to the sharing of non-public data concerning inventory levels and the potential uses of such data in natural gas trading. On June 15, 2005, the FERC approved a settlement in which we paid refunds and a penalty totaling $7.6 million.

Mobile Bay expansion

On December 3, 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. The administrative law judge's initial decision is subject to review by the FERC. On March 26, 2004, the FERC issued an Order on Initial Decision in which it reversed certain parts of the administrative law judge's holding 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 $68 million, excluding interest, through June 30, 2005, in addition to increased costs going forward. On April 26, 2004, several parties, including Transco, filed requests for rehearing of the FERC's March 26, 2004 order. These requests are still pending.

Enron bankruptcy

We have outstanding claims against Enron Corp. and various of its subsidiaries (collectively "Enron") related to Enron's bankruptcy filed in December 2001. In March 2002, we sold $100 million of our claims against Enron to a third party for $24.5 million. On December 23, 2003, Enron filed objections to these claims. Under the sales agreement, the purchaser of the claims may demand repayment of the purchase price, plus interest assessed at an annual rate of 7.5 percent, for that portion of the claims still subject to objections beginning 90 days following the initial objection. To date, the purchaser has not demanded repayment.

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 June 30, 2005, Transco had accrued liabilities of $22 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, Transco has estimated its aggregate exposure for remediation of these sites to be less than $500,000, which is included in the environmental accrual discussed above.

We also accrue environmental remediation costs for our natural gas gathering and processing facilities, primarily related to soil and groundwater contamination. At June 30, 2005, we had accrued liabilities totaling approximately $8 million for these costs.

Actual costs incurred for these matters will depend on the actual number of contaminated sites identified, the amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors.

In August 2004, the New Mexico Environment Department (NMED) issued a Notice of Violation (NOV) to one of our subsidiaries, Williams Field Services Company (WFS), alleging various air permit violations primarily related to WFS's alleged failure to control volatile organic compound emissions from three conventional dehydrators in 2001. Additionally, in August 2004, we discovered and self-disclosed to the NMED that WFS was out of compliance with certain requirements of the operating permit issued under Title V of the Clean Air Act Amendments of 1990 at the Kutz gas processing plant. Both of these matters have been resolved.

Former operations, including operations classified as discontinued

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

Agrico

In connection with the 1987 sale of the assets of Agrico Chemical Company, we agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations to the extent such costs exceed a specified amount. At June 30, 2005, we had accrued liabilities of approximately $11 million for such excess costs.

We are also in discussions with defendants involved in two class action damages lawsuits involving this former chemical fertilizer business. Settlement among those defendants 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 has filed a Motion to Compel us to participate in arbitration regarding the contractual obligations. A hearing was held on that Motion on September 2, 2004, and the judge ordered the Motion to Compel and subsequent issues severed from the class action. On November 3, 2004, we removed the severed case to the United States District Court in the Northern District of Florida in Pensacola. Agrico filed its Motion to Remand on November 22, 2004. We filed a subsequent Motion to Dismiss on January 21, 2005. A hearing on the Motion to Remand was held on March 23, 2005. The Court did not rule from the bench and its decision is still pending.

Notes (Continued)

Other

At June 30, 2005, we have accrued environmental liabilities totaling approximately $28 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; and
- 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 to the EPA a self-disclosure letter 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. On August 25, 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 multi-media report, including the benzene NESHAP issue. Discussion between the EPA, the DOJ and Williams Refining to resolve the allegations of noncompliance are ongoing. In connection with the sale of the Memphis refinery in March 2003, there are certain indemnification obligations to the purchaser.

In January 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 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 anticipate negotiation of a resolution with the current plant owner and the ODEQ.

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

Summary of environmental matters

Actual costs incurred for these matters could be substantially greater than amounts accrued depending on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors.

Other legal matters

Royalty indemnifications

In connection with agreements 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 which the producers may be required to pay as a result of such settlements. Transco, through its agent, Power, continues to purchase gas under contracts which extend, in some cases, through the life of the associated gas reserves. Certain of these contracts contain royalty indemnification provisions that have no carrying value. Producers have received 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.

Notes (Continued)

As a result of these settlements, Transco has been sued by certain producers seeking indemnification from Transco. Transco is currently a defendant in one lawsuit in which a producer has asserted damages, including interest calculated through June 30, 2005, of approximately $10 million. On July 11, 2003, at the conclusion of the trial, the judge ruled in Transco's favor and subsequently entered a formal judgment. However, the plaintiff has appealed.

Will Price (formerly Quinque)

On June 8, 2001, fourteen of our entities were named as defendants in a nationwide class action lawsuit which had been pending against other defendants, generally pipeline and gathering companies, since 2000. The plaintiffs allege that the defendants, including us, 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. After the court denied class action certification and while motions to dismiss for lack of personal jurisdiction were pending, the court granted the plaintiffs' motion to amend their petition on July 29, 2003. The fourth amended petition, which was filed on July 29, 2003, deletes all of our defendants except two Midstream subsidiaries. All defendants have opposed class certification, and a hearing on plaintiffs' second motion to certify the class was held on April 1, 2005. We anticipate receiving a decision later in 2005.

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. On April 9, 1999, the DOJ announced that it was declining to intervene in any of the Grynberg *qui tam* cases, including the action filed in federal court in Colorado against us. On October 21, 1999, the Panel on Multi-District Litigation transferred all of the Grynberg *qui tam* 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. The defendants filed a number of joint motions to dismiss Grynberg's claims on subject matter jurisdictional bases. In May 2005, the court-appointed special master entered a report which recommended that the claims against our Gas Pipeline and Midstream subsidiaries be dismissed but upheld the claims against our Exploration & Production subsidiaries against our jurisdictional challenge. In June 2005, the defendants, including our defendant subsidiaries, filed motions to adopt and modify the special master's report and recommendation.

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 the defendants 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 defendants 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. Our motion to stay the proceedings in this case based on the pendency of the False Claims Act litigation discussed in the preceding paragraph was granted in January 2003. In September 2004, Grynberg successfully moved to lift the stay and 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.

Notes (Continued)

Securities class actions

Numerous shareholder class action suits have been filed against us 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 filed 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. The amended complaint of the WilTel securities holders was filed in September 2002, and the amended complaint of our securities holders was filed in October 2002. This amendment added numerous claims related to Power. Defendants moved to dismiss the complaints and the Court largely denied the motions. The parties are currently engaged in discovery. On April 2, 2004, the lead plaintiff for the purported class of our securities holders filed a partial motion for summary judgment with respect to certain disclosures made in connection with our public offerings during the class period. That lead plaintiff subsequently filed to withdraw from the proceeding and a new process was held to determine the lead plaintiff. This process has concluded with the appointment of a new lead plaintiff and lead counsel and the motion for summary judgment is no longer being pursued. The appointment of a new lead plaintiff also resulted in a revised schedule with a trial date currently set for August 16, 2006. 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, but there can be no assurance that the ultimate resolution of this litigation will not include some amount outside of insurance coverage.

In addition, four class action complaints have been filed against us, the members of our Board of Directors and members of our benefits and investment committees under the Employee Retirement Income Security Act (ERISA) by participants in our 401(k) plan. A motion to consolidate these suits has been approved. In July 2003, the court dismissed us and our Board from the ERISA suits, but not the members of the benefits and investment committees to whom we might have an indemnity obligation. If it is determined that we have an indemnity obligation, we expect that any costs incurred will be covered by our insurance policies. On June 7, 2004, the Court granted plaintiffs' request to amend their complaint to add additional investment committee members and to again name the Board of Directors. On December 21, 2004, the Court denied the Plaintiffs' Motion for Partial Summary Judgment against the Director Defendants and denied the Motions to Dismiss filed by the Directors and certain Committee Defendants. On April 26, 2005, Plaintiffs filed a Third Amended Complaint again adding us as a defendant in this matter. The U.S. Department of Labor is also independently investigating our employee benefit plans. We are currently engaged in preliminary mediated settlement discussions related to this matter.

Oklahoma securities investigation

On April 26, 2002, the Oklahoma Department of Securities issued an order initiating an investigation of us and WilTel regarding issues associated with the spin-off of WilTel and regarding the WilTel bankruptcy. We have no pending inquiries in this investigation, but are committed to cooperate fully in the investigation.

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.

Notes (Continued)

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. The FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions during the third quarter of 2004. 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. Interest on the Quality Bank accrual is being accrued each quarter. 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 RCA, to result in additional exposure to us of approximately $32 million more than we have accrued at June 30, 2005. We filed a brief on exceptions to the initial decisions to both the FERC and RCA on November 16, 2004, and our reply briefs on February 1, 2005. Decisions from the FERC and RCA may be issued before the end of 2005 or early in 2006. Settlement discussions have been initiated. Absent the completion of any settlements, it is unlikely that we will be required to make any payments with respect to this matter until sometime after the FERC and RCA decisions.

Notwithstanding the regulatory proceedings, our exposure could be affected by the 2005 Highway Reauthorization Bill, passed by both Houses of the United States Congress on Friday, July 29, 2005, and which is now expected to be signed into law sometime before August 14, 2005, by the President. This new bill, if signed into law and upheld in its current form, could significantly reduce our potential liability by eliminating the retroactive impact of Quality Bank adjustments for years prior to 2000.

Deepwater construction litigation

In a lawsuit pending in federal court in Houston, Texas, Technip Offshore, Inc. (Technip) is seeking approximately $8.6 million from two of our subsidiaries. The suit alleges that we breached a contract for the construction of deepwater export pipelines connected to the Devils Tower Spar in the Gulf of Mexico. We have filed counterclaims seeking $4.2 million in liquidated delay damages. Each party has posted a letter of credit covering the value of the claims pending against it.

Colorado royalty litigation

On June 27, 2002, a royalty owner in the Piceance basin of Colorado filed suit against one of our Exploration & Production subsidiaries alleging that we breached our lease agreements and violated the Colorado Deceptive Trade Practices Act (CDTA) by making various deductions from his royalty payments from 1996 to date. On August 2, 2004, the jury returned its verdict in the amount of $4.1 million for the plaintiff. The verdict included a finding under the CDTA which could have potentially tripled the damage award. On November 30, 2004, the court issued an order setting aside the plaintiff's CDTA claims, but left intact the $4.1 million award. We are appealing the judgment to the Colorado Court of Appeals.

Redondo Beach taxes

On February 5, 2005, Power received a tax assessment letter, addressed to AES Redondo Beach, L.L.C. and Power, from the city of Redondo Beach, California, in which the city asserted that approximately $33 million in back taxes and approximately $39 million in interest and penalties are owed related to natural gas used at the generating facility operated by AES Redondo Beach. 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 and requested an additional briefing. To the extent such taxes are ultimately determined to be owed under Power's tolling agreement related to the Redondo Beach generating facility, we believe that AES Redondo Beach is responsible for taxes of the nature asserted by the city. A decision is expected during the third quarter of 2005.

San Juan basin gas entitlements

One of our Exploration & Production subsidiaries is involved in a dispute with another joint interest owner in multiple federal oil and gas units located in the San Juan basin. The dispute involves various accounting issues relating to payout determinations in these federal units and associated claims for retroactive adjustment of entitlements to gas production. We have settled these disputes for a payment of approximately $23.5 million.

Notes (Continued)

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 June 30, 2005, 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 June 30, 2005, Power's estimated committed payments under these contracts range from approximately $401 million to $424 million annually through 2017 and decline over the remaining five years to $59 million in 2022. Total committed payments under these contracts over the next eighteen years are approximately $6.1 billion.

Guarantees

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 entered against the bank that we will have to pay. The carrying value of this guarantee is $0.1 million at June 30, 2005.

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, 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 2006 and have no carrying value.

Notes (Continued)

We have provided guarantees in the event of nonpayment by WilTel on certain lease performance obligations that extend through 2042 and have a maximum exposure of approximately $48 million at June 30, 2005. Our exposure declines systematically throughout the remaining term of WilTel's obligations. The carrying value of these guarantees is approximately $44 million at June 30, 2005.

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 June 30, 2005.

Former managing directors of Gulf Liquids are involved in litigation related to the construction of the gas processing plants. Gulf Liquids has indemnity obligations to the former directors 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 litigation. However, we believe the probability is remote that a judgment will be entered against the former directors that we will have to pay. These legal fees and any judgment should be recoverable under a directors and officers insurance policy; thus, no amounts have been accrued for this contingent obligation.

13. Comprehensive income (loss)

Comprehensive income (loss) is as follows:

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(Millions)		(Millions)	
Net income (loss)	$ 41.3	$(18.2)	$ 242.4	$ (8.3)
Other comprehensive income (loss):				
Net realized losses on securities	—	—	—	3.0
Unrealized gains (losses) on derivative instruments	55.7	(83.8)	(272.9)	(268.4)
Net reclassification into earnings of derivative instrument losses	54.7	51.3	122.5	98.0
Foreign currency translation adjustments	(2.9)	(6.2)	(5.1)	(11.5)
Minimum pension liability adjustment	—	—	—	.7
Other comprehensive income (loss) before taxes	107.5	(38.7)	(155.5)	(178.2)
Income tax (provision) benefit on other comprehensive income (loss)	(42.3)	12.3	57.5	63.7
Other comprehensive income (loss)	65.2	(26.4)	(98.0)	(114.5)
Comprehensive income (loss)	$106.5	$(44.6)	$ 144.4	$(122.8)

14. Segment disclosures

Segments and reclassification of operations

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 and certain continuing operations that were included within the previously reported International and Petroleum Services segments.

Segments — performance measurement

We currently evaluate performance based upon segment profit (loss) from operations, which includes revenues from external and internal customers, operating costs and expenses, depreciation, depletion and amortization, equity earnings (losses) and income (loss) from investments including gains/losses on 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.

During 2004, Power was party to intercompany interest rate swaps with the corporate parent, the effect of which is included in Power's segment revenues and segment profit (loss) as shown in the reconciliation within the following tables. The results of interest rate swaps with external counterparties are shown as Interest rate swap income (loss) in the Consolidated Statement of Operations below operating income. These swaps were terminated in the fourth quarter of 2004.

The majority of energy commodity hedging by certain of our business units is done through intercompany derivatives with Power 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 intercompany sales.

Notes (Continued)

14. Segment disclosures (Continued)

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

	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids (Millions)	Other	Eliminations	Total
Three months ended June 30, 2005							
Segment revenues:							
External	$1,788.0	$353.3	$ (40.4)	$768.7	$ 1.6	$ —	$2,871.2
Internal	211.4	3.7	321.9	11.4	4.5	(552.9)	—
Total segment revenues	$1,999.4	$357.0	$281.5	$780.1	$ 6.1	$(552.9)	$2,871.2
Segment profit (loss)	$ (75.0)	$164.5	$118.3	$109.1	$(60.5)	$ —	$ 256.4
Less:							
Equity earnings (losses)	.9	7.9	3.6	4.1	(6.7)	—	9.8
Income (loss) from investments	—	—	—	.7	(49.1)	—	(48.4)
Segment operating income (loss)	$ (75.9)	$156.6	$114.7	$104.3	$ (4.7)	$ —	295.0
General corporate expenses							(35.5)
Consolidated operating income							$ 259.5
Three months ended June 30, 2004							
Segment revenues:							
External	$2,118.7	$325.9	$ (19.3)	$624.5	$ 2.1	$ —	$3,051.9
Internal	235.0	5.1	208.3	9.2	4.9	(462.5)	—
Total segment revenues	2,353.7	331.0	189.0	633.7	7.0	(462.5)	3,051.9
Less intercompany interest rate swap income	20.5	—	—	—	—	(20.5)	—
Total revenues	$2,333.2	$331.0	$189.0	$633.7	$ 7.0	$(442.0)	$3,051.9
Segment profit (loss)	$ 43.8	$132.8	$ 43.3	$ 98.5	$(14.3)	$ —	$ 304.1
Less:							
Equity earnings (losses)	(.9)	5.2	3.2	3.5	(.3)	—	10.7
Loss from investments	—	(.7)	—	(.1)	(10.8)	—	(11.6)
Intercompany interest rate swap income	20.5	—	—	—	—	—	20.5
Segment operating income (loss)	$ 24.2	$128.3	$ 40.1	$ 95.1	$ (3.2)	$ —	284.5
General corporate expenses							(28.4)
Consolidated operating income							$ 256.1

	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids (Millions)	Other	Eliminations	Total
Six months ended June 30, 2005							
Segment revenues:							
External	$3,639.0	$685.1	$ (68.3)	$1,565.0	$ 4.4	$ —	$5,825.2
Internal	425.3	7.2	598.8	22.1	8.7	(1,062.1)	—
Total segment revenues	$4,064.3	$692.3	$530.5	$1,587.1	$ 13.1	$(1,062.1)	$5,825.2
Segment profit (loss)	$ 39.1	$331.9	$222.0	$ 237.7	$(64.6)	$ —	$ 766.1
Less:							
Equity earnings (losses)	2.0	19.3	7.1	11.2	(12.1)	—	27.5
Income (loss) from investments	—	—	—	.7	(49.1)	—	(48.4)
Segment operating income	$ 37.1	$312.6	$214.9	$ 225.8	$ (3.4)	$ —	787.0
General corporate expenses							(63.5)
Consolidated operating income							$ 723.5
Six months ended June 30, 2004							
Segment revenues:							
External	$4,222.6	$681.2	$ (34.1)	$1,247.3	$ 4.9	$ —	$6,121.9
Internal	405.9	8.8	388.3	18.2	14.7	(835.9)	—

Total segment revenues	4,628.5	690.0	354.2	1,265.5	19.6	(835.9)	6,121.9
Less intercompany interest rate swap loss	(1.1)	—	—	—	—	1.1	—
Total revenues	$4,629.6	$690.0	$354.2	$1,265.5	$ 19.6	$ (837.0)	$6,121.9
Segment profit (loss)	$ 11.8	$280.2	$ 94.8	$ 208.6	$(23.0)	$ —	$ 572.4
Less:							
Equity earnings (losses)	(.2)	9.0	6.1	7.7	(.3)	—	22.3
Loss from investments	—	(1.0)	—	(.3)	(17.3)	—	(18.6)
Intercompany interest rate swap loss	(1.1)	—	—	—	—	—	(1.1)
Segment operating income (loss)	$ 13.1	$272.2	$ 88.7	$ 201.2	$ (5.4)	$ —	569.8
General corporate expenses							(60.4)
Consolidated operating income							$ 509.4

Notes (Continued)

14. Segment disclosures (Continued)

The following table reflects total assets by reporting segment.

	Total Assets	
	June 30, 2005	December 31, 2004
	(Millions)	
Power (1)	$10,522.0	$ 8,204.1
Gas Pipeline	7,462.2	7,651.8
Exploration & Production	5,811.2	5,576.4
Midstream Gas & Liquids	4,433.6	4,211.7
Other	3,610.3	3,584.0
Eliminations	(5,452.4)	(5,248.6)
	26,386.9	23,979.4
Discontinued operations	12.8	13.6
Total	$26,399.7	$23,993.0

(1) The increase in Power's total assets is due primarily to an increase in derivative assets as a result of increases in natural gas prices on existing forward gas purchase derivative contracts.

15. Recent accounting standards

In November 2004, the FASB issued SFAS No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which will be applied prospectively for inventory costs incurred in fiscal years beginning after June 15, 2005. The Statement amends Accounting Research Bulletin (ARB) No. 43, Chapter 4, "Inventory Pricing," to clarify the accounting for abnormal amounts of certain costs and the allocation of overhead costs. We are assessing the impact of this Statement on our Consolidated Financial Statements and believe the effect will not be material.

In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29," which is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005, and will be applied prospectively. The Statement amends APB Opinion No. 29, "Accounting for Nonmonetary Transactions." The guidance in APB Opinion No. 29 is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged but includes certain exceptions to that principle. SFAS No. 153 amends APB Opinion No. 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. We will apply SFAS No. 153 as required.

In March 2005, the FASB issued a Staff Position (FSP) on a previously issued Interpretation (FIN). FSP FIN 46(R)-5, "Implicit Variable Interests under revised FASB Interpretation No. 46 (FIN 46(R)), *Consolidation of Variable Interest Entities*," states that a reporting enterprise must consider implicit variable interests when applying the provisions of FIN 46(R). The FSP was effective in the second quarter of 2005 and does not have a material impact on our consolidated financial position and results of operations.

In March 2005, the FASB issued FIN 47, "Accounting for Conditional Asset Retirement Obligations — an interpretation of FASB Statement No. 143." The Interpretation clarifies that the term *conditional asset retirement obligation*, as used in SFAS No. 143, "Accounting for Asset Retirement Obligations," refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. The effective date of this Interpretation is no later than the end of the fiscal year ending after December 15, 2005. We are assessing the impact of this Interpretation on our Consolidated Financial Statements and believe the effect will not be material.

In April 2005, the FASB staff issued FSP FAS 19-1, "Accounting for Suspended Well Costs." This FSP amends SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," as it pertains to capitalizing the costs of drilling exploratory wells pending determination of whether the well has found proved reserves. FSP FAS 19-1 provides that exploratory well costs should continue to be capitalized if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the entity is making sufficient

Notes (Continued)

progress assessing the reserves and the economic and operational viability of the project. This FSP is effective beginning in the third quarter of 2005 and will not have a material impact on our consolidated financial position and results of operations.

In December 2004, the Financial Accounting Standards Board (FASB) issued revised SFAS No. 123, "Share-Based Payment." The Statement requires that compensation costs for all share-based awards to employees be recognized in the financial statements at fair value. The Statement, as issued by the FASB, was to be effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. However, on April 15, 2005, the Securities and Exchange Commission (SEC) adopted a new rule that amends the compliance dates for revised SFAS No. 123. The rule allows implementation of the Statement at the beginning of the next fiscal year that begins after June 15, 2005. We intend to adopt the revised Statement as of January 1, 2006.

The revised Statement allows either a modified prospective application or a modified retrospective application for adoption. We will use a modified prospective application for adoption and thus will apply the statement to new awards and to awards modified, repurchased, or cancelled after January 1, 2006. Also, for unvested stock awards outstanding as of January 1, 2006, compensation costs for the portion of these awards for which the requisite service has not been rendered will be recognized as the requisite service is rendered after January 1, 2006. Compensation costs for these awards will be based on fair value at the original grant date as estimated for the pro forma disclosures under SFAS No. 123, as amended by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of SFAS No. 123." Additionally, a modified retrospective application requires restating periods prior to January 1, 2006, on a basis consistent with the pro forma disclosures required by SFAS No. 123, "Accounting for Stock-Based Compensation," as amended by SFAS No. 148. Since we plan to use a modified prospective application, we will not restate prior periods.

In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections — a replacement of APB Opinion No. 20 and FASB Statement No. 3," which is effective for reporting a change in accounting principle for fiscal years beginning after December 15, 2005. The Statement changes the reporting of a change in accounting principle to require retrospective application to prior periods' financial statements, except for explicit transition provisions provided for in new accounting pronouncements or existing accounting pronouncements, including those in the transition phase when SFAS No. 154 becomes effective. We will apply SFAS No. 154 as required.

In June 2005, the FASB ratified EITF Issue No. 04-10, "Determining Whether to Aggregate Operating Segments That Do Not Meet the Quantitative Thresholds." The consensus is effective for fiscal years ending after September 15, 2005, and will not affect the current presentation of our reportable operating segments.

In June 2005, the FASB ratified EITF Issue No. 05-2, "The Meaning of Conventional Convertible Debt Instrument in EITF Issue No. 00-19, *Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company's Own Stock*." The consensus is to be applied prospectively for new instruments entered into or existing instruments modified in periods beginning after June 29, 2005. We have outstanding 5.5 percent junior subordinated convertible debentures that were considered conventional convertible debt at issuance. This Issue does not currently impact these debentures. If we were to modify these debentures, we would have to evaluate the terms of the instruments after the modification to determine if they would remain a conventional convertible debt instrument.

On June 30, 2005, the FERC issued an order, "Accounting for Pipeline Assessment Cost," to be effective January 1, 2006. The order requires companies to expense certain assessment costs that we have historically capitalized. We are assessing the financial impact of the order and anticipate receiving updates throughout the remainder of 2005. The Interstate Natural Gas Association of America, an industry trade association, has filed for rehearing of this order.

ITEM 2

Management's Discussion and Analysis of Financial Condition and Results of Operation

Recent events and company outlook

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2004, we entered 2005 having completed the key components of our restructuring plan and in a position to shift our focus to growth. Our Plan for 2005 includes the following objectives:

- increase focus and disciplined EVA®-based investment in natural gas businesses;
- continue to steadily improve credit ratios and rating with the goal of achieving investment grade ratios;
- continue to reduce risk and liquidity requirements while maximizing cash flow in the Power segment;
- maintain liquidity from cash and revolving credit facilities of at least $1 billion; and
- generate sustainable growth in EVA® and shareholder value.

During 2005, we have continued to improve our credit ratios. In January, we retired $200 million of debt which matured January 15, 2005. On February 16, the holders of the remaining 10.9 million equity forward contracts associated with the FELINE PACS units exercised contracts to purchase one share of our common stock for $25 a share, resulting in cash proceeds of approximately $273 million. The remaining notes associated with the FELINE PACS units totaling approximately $73 million are due February 16, 2007.

On May 2, 2005, Williams Partners L.P. filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of five million common units, representing limited partnership interests in Williams Partners L.P., plus an option for the underwriters to purchase up to an additional 750,000 common units. On June 24, 2005, July 18, 2005, and August 3, 2005, Williams Partners L.P. filed amendments to the registration statement.

General

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the consolidated financial statements and notes in Item 1 reflect the results of operations, financial position and cash flows through the date of sale, as applicable, of the following components as discontinued operations (see Note 5 of Notes to Consolidated Financial Statements):

- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment; and
- our straddle plants in western Canada, previously part of the Midstream segment.

During fourth-quarter 2004, we reclassified the operations of Gulf Liquids to continuing operations within our Midstream segment in accordance with EITF 03-13, which was issued in the fourth quarter. Under the provisions of EITF 03-13, Gulf Liquids activities no longer qualified for reporting as discontinued operations, based on management's expectation that we will continue to have significant commercial activity with the disposed entity. The operations of Gulf Liquids were reclassified to continuing operations within our Midstream segment. All periods presented reflect this reclassification.

At March 31, 2005, all of the assets and liabilities of Gulf Liquids, which are not material to our Consolidated Balance Sheet, were classified as held for sale and included in Other current assets and deferred charges and Accrued liabilities. During second-quarter 2005, we decided to retain a portion of the Gulf Liquids operations and reclassified certain of the assets and liabilities from held for sale to held for use. The sale of the remaining assets held for sale closed on July 15, 2005.

Unless indicated otherwise, the following discussion and analysis of results of operations, financial condition and liquidity 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 2004 Annual Report on Form 10-K. In addition, certain amounts have been reclassified to conform to the current classification.

Management's Discussion and Analysis (Continued)

Results of operations

Consolidated overview

The following table and discussion is a summary of our consolidated results of operations for the three and six months ended June 30, 2005, compared to the three and six months ended June 30, 2004. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended June 30,			Six months ended June 30,		
	2005	2004	% Change from 2004 (1)	2005	2004	% Change from 2004 (1)
	(Millions)			(Millions)		
Revenues	$2,871.2	$3,051.9	-6%	$5,825.2	$6,121.9	-5%
Costs and expenses:						
Costs and operating expenses	2,491.6	2,661.4	+6%	4,881.9	5,352.3	+9%
Selling, general and administrative expenses	62.7	82.8	+24%	136.2	168.3	+19%
Other expense – net	21.9	23.2	+6%	20.1	31.5	+36%
General corporate expenses	35.5	28.4	-25%	63.5	60.4	-5%
Total costs and expenses	2,611.7	2,795.8	+7%	5,101.7	5,612.5	+9%
Operating income	259.5	256.1	+1%	723.5	509.4	+42%
Interest accrued – net	(163.2)	(221.6)	+26%	(326.8)	(460.9)	+29%
Interest rate swap income (loss)	—	6.8	-100%	—	(1.3)	+100%
Investing income (loss)	(17.2)	11.6	NM	13.8	22.0	-37%
Early debt retirement costs	—	(96.8)	+100%	—	(97.3)	+100%
Minority interest in income of consolidated subsidiaries	(4.8)	(6.0)	+20%	(10.0)	(10.8)	+7%
Other income – net	8.1	13.6	-40%	13.6	14.9	-9%
Income (loss) from continuing operations before income taxes	82.4	(36.3)	NM	414.1	(24.0)	NM
Provision (benefit) for income taxes	41.7	(17.8)	NM	171.2	(5.5)	NM
Income (loss) from continuing operations	40.7	(18.5)	NM	242.9	(18.5)	NM
Income (loss) from discontinued operations	.6	.3	+100%	(.5)	10.2	NM
Net income (loss)	$ 41.3	$ (18.2)	NM	$ 242.4	$ (8.3)	NM

(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.

Consolidated Overview

Three Months Ended June 30, 2005 vs. Three Months Ended June 30, 2004

The $180.7 million decrease in Revenues is due primarily to decreased revenues at Power resulting primarily from the absence of crude and refined products activity, the absence of a 2004 realized gain from the interest rate portfolio and reduced net forward unrealized mark-to-market gains. The absence of crude and refined products activity is due to the sale of the crude and refined products business in the second half of 2004. Partially offsetting the decrease at Power is an increase in revenues at Midstream and Exploration & Production associated with higher commodity prices and increased volumes.

The $169.8 million decrease in Costs and operating expenses is due primarily to decreased costs and operating expenses at Power, partially offset by increased costs and operating expenses in support of increased sales at Midstream. The decrease at Power is due primarily to the absence of crude and refined product costs in 2005.

The $20.1 million decrease in Selling, general and administrative (SG&A) expenses is due primarily to a $17.1 million reduction to expense to record the cumulative impact of a correction of an error attributable to the periods 2003 and 2004.

Other expense — net, within operating income, in 2005 includes:

- a $13.1 million accrual for litigation contingencies at Power; and
- a $4 million write-off of project costs in our Other segment.

Other expense — net, within operating income, in 2004 includes:

- an $11.3 million loss provision related to an ownership dispute on prior period production included at Exploration & Production; and
- a $9 million write-off of previously capitalized costs on an idled segment of Northwest Pipeline's system.

The $7.1 million increase in General corporate expenses is due primarily to increased outside legal costs associated with ongoing claims.

The $58.4 million decrease in Interest accrued — net is due primarily to lower average borrowing levels in second-quarter 2005 as compared to second-quarter 2004.

In 2004, we entered into interest rate swaps with external counterparties primarily in support of the energy-trading portfolio. We terminated all interest-rate derivatives in the fourth quarter of 2004. The change in fair market value of these swaps was $6.8 million favorable for the second quarter of 2004.

The $28.8 million decrease in Investing income (loss) is due primarily to:

- a $38.3 million larger Longhorn investment impairment in 2005 than in 2004; and
- $6.7 million of equity losses related to Longhorn second-quarter operations.

Offsetting these decreases are:

- an $8.6 million gain on the sale of our remaining interests in the MAPL and Seminole assets; and
- $3 million higher equity earnings from our investment in Gulfstream Natural Gas System, L.L.C. (Gulfstream).

Early debt retirement costs for 2004 includes premiums, fees and expenses related to the debt repurchase and consent solicitations that we completed in the second quarter.

Provision for income taxes increased $59.5 million due primarily to higher pre-tax income in second-quarter 2005. The effective income tax rate for second-quarter 2005 is greater than the federal statutory rate due primarily to the effect of state income taxes, nondeductible expenses, and an accrual for income tax contingencies. The effective income tax rate benefit for second-quarter 2004 was greater than the federal statutory rate due primarily to the effect of state income taxes, partially offset by net foreign operations.

Six Months Ended June 30, 2005 vs. Six Months Ended June 30, 2004

The $296.7 million decrease in Revenues is due primarily to decreased revenues at Power primarily resulting from lower power sales volumes and the absence of crude and refined products activity, partially offset by increased unrealized mark-to-market gains. Partially offsetting the decrease at Power was an increase in revenues at Midstream and Exploration & Production associated with higher commodity prices and increased volumes.

The $470.4 million decrease in Costs and operating expenses is due primarily to decreased costs at Power, partially offset by increased costs and operating expenses in support of increased sales volumes at Midstream. The decrease at Power is due primarily to lower power purchase volumes and the absence of crude and refined products costs.

Table of Contents

The $32.1 million decrease in SG&A expenses is due primarily to a $17.1 million reduction to expense to record the cumulative impact of a correction of an error attributable to the periods 2003 and 2004, lower reimbursable costs (offset in revenues), and accounting corrections at Transco related to prior period overstatements.

Other expense — net, within operating income, in 2005 includes:

- a $13.1 million accrual for litigation contingencies at Power;
- a $4.6 million accrual for a regulatory settlement at Power;
- a $7.9 million gain on the sale of an undeveloped leasehold in Colorado at Exploration & Production;
- $5.5 million of gains from the sale of Exploration & Production's securities, invested in a coal seam royalty trust, which were purchased for resale; and
- a $4 million write-off of project costs in our Other segment.

Other expense — net, within operating income, in 2004 includes:

- an $11.3 million loss provision related to an ownership dispute on prior period production included at Exploration & Production;
- a $9 million write-off of previously capitalized costs on an idled segment of Northwest Pipeline's system; and
- a $6.1 million charge for fees related to the sale of receivables to Bear Stearns.

The $134.1 million decrease in Interest accrued — net is due primarily to lower average borrowing levels in 2005 as compared to 2004.

In 2004, we entered into interest rate swaps with external counterparties primarily in support of the energy-trading portfolio. We terminated all interest-rate derivatives in the fourth quarter of 2004. The change in fair market value of these swaps was $1.3 million unfavorable for the six months ended June 30, 2004.

The $8.2 million decrease in Investing income (loss) is due primarily to:

- a $38.3 million larger Longhorn investment impairment in 2005 than in 2004; and
- $12.2 million of equity losses related to Longhorn.

Offsetting these decreases are:

- $10.7 million higher equity earnings from Gulfstream;
- an $8.6 million gain on the sale of our remaining interests in the MAPL and Seminole assets;
- the absence of $6.5 million net unreimbursed Longhorn recapitalization advisory fees recognized in 2004;
- $5.5 million income from certain international cost-based investments; and
- the absence in 2005 of $5.1 million of impairments of certain international and other cost-based investments during 2004.

Early debt retirement costs for 2004 includes premiums, fees and expenses related to the debt repurchase and consent solicitations that we completed in the second quarter.

Provision for income taxes increased $176.7 million due primarily to higher pre-tax income in 2005. The effective income tax rate for 2005 is greater than the federal statutory rate due primarily to the effect of state income taxes, nondeductible expenses and an accrual for income tax contingencies. The effective income tax rate benefit for 2004 was less than the federal statutory rate due primarily to the effect of net foreign operations and an accrual for income tax contingencies, partially offset by the effect of state income taxes.

Income (loss) from discontinued operations decreased $10.7 million primarily due to the absence in 2005 of income from the Canadian straddle plants, which were sold in third-quarter 2004. Additionally, 2005 results reflect the absence of the gains on sale of the Alaska assets and our interest in Williams Energy Partners, both of which were sold in first-quarter 2004.

Results of operations — segments

We are currently organized into the following reporting segments: Power, Gas Pipeline, Exploration & Production, Midstream and Other. Other primarily consists of corporate operations and certain continuing operations formerly included in the previously reported International and Petroleum Services segments. Our management currently evaluates performance based on segment profit (loss) from operations (see Note 14 of Notes to Consolidated Financial Statements).

Power

Overview of six months ended June 30, 2005

Power's operating results in the first half of 2005 were significantly influenced by the effect of price changes on power and natural gas derivative contracts, which caused forward unrealized mark-to-market gains on the portion of the portfolio that does not qualify for hedge accounting.

In the first half of 2005, 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 the following:

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

Outlook for the remainder of 2005

For the remainder of 2005, Power intends to service its customers' needs while increasing the certainty of cash flows from its long-term contracts.

As Power continues to apply hedge accounting in 2005, its future earnings may be less volatile. However, not all of Power's derivative contracts qualify for hedge accounting. Power will continue to report changes in the fair value of those remaining non-hedge contracts in earnings as unrealized gains or losses. In addition, the ineffective portion of the change in the forward fair value of qualifying hedges will also be reported in earnings. Because the 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 will reflect losses from underlying 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 adoption of hedge accounting, some variability in Power's earnings will remain as a result of:

- market movements of commodity-based derivatives held for trading purposes or which did not qualify for hedge accounting; and
- 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 are 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 gains or losses as a result of the volatile nature of energy commodity markets. The inability of counterparties to perform under contractual obligations due to their own credit constraints could also affect future operations.

Period-over-period results

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(Millions)		(Millions)	
Realized revenues	$1,977.3	$2,283.9	$3,821.1	$4,535.0
Net forward unrealized mark-to-market gains	22.1	69.8	243.2	93.5
Segment revenues	1,999.4	2,353.7	4,064.3	4,628.5
Cost of sales	2,034.5	2,281.5	3,959.5	4,557.7
Gross margin	(35.1)	72.2	104.8	70.8
Operating expenses	6.6	6.2	11.9	12.6
Selling, general and administrative expenses	16.9	20.0	32.9	36.2
Other expense — net	(16.4)	(2.2)	(20.9)	(10.2)
Segment profit (loss)	$ (75.0)	$ 43.8	$ 39.1	$ 11.8

Three months ended June 30, 2005 vs. three months ended June 30, 2004

The $354.3 million decrease in revenues includes a $306.6 million decrease in realized revenues and a $47.7 million decrease in net forward unrealized mark-to-market gains.

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. The $306.6 million decrease in realized revenues is primarily due to the absence in second-quarter 2005 of $279 million in crude and refined products realized revenues and a $34 million realized gain from the interest rate portfolio. The decrease is partially offset by a $6 million increase in power and natural gas realized revenues.

The absence of crude and refined products revenues is due to the sale of the refined products business in 2004. The absence of activity in the interest rate portfolio is due to the termination and liquidation of all remaining interest-rate derivatives in fourth-quarter 2004. In second-quarter 2004, an increase in interest rates caused a realized gain on interest rate derivatives. Power and natural gas realized revenues increased primarily due to a 16 percent increase in average natural gas sales prices and a 13 percent increase in average power sales prices. Largely offsetting this increase is a 29 percent decrease in power sales volumes. 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 represent changes in the fair value of certain derivative contracts with a future settlement or delivery date that have not been designated as cash flow hedges and the ineffectiveness of cash flow hedges. The $47.7 million decrease in net forward unrealized gains is primarily due to a $40 million decrease associated with power and gas contracts and the absence in 2005 of the $10 million unrealized gain on the interest rate portfolio in 2004. The decrease in power and gas primarily results from cash flow hedge accounting, which was prospectively applied to certain of Power's forecasted transactions beginning October 1, 2004. Net unrealized gains of $144 million related to the effective portion of the hedges are reported in Accumulated other comprehensive loss in second-quarter 2005. The absence in 2005 of the unrealized gain on the interest rate portfolio is due to the termination and liquidation of all remaining interest-rate derivatives in fourth-quarter 2004. An increase in forward interest rates caused unrealized gains in the interest rate portfolio in second-quarter 2004.

The $247 million decrease in Power's cost of sales is primarily due to the absence in second-quarter 2005 of crude and refined products costs of $280 million partially offset by an increase in power and natural gas costs of $33 million. The absence of crude and refined products costs is due to the sale of the refined products business in 2004. Power and natural gas costs increased primarily due to a 14 percent increase in both average natural gas purchase prices and average power purchase prices. Also, costs in second-quarter 2004 reflect a $10.4

million reduction to certain contingent loss accruals associated with power marketing activities in California during 2000 and 2001. Partially offsetting the increase in power and natural gas costs is a 29 percent decrease in power purchase volumes.

Other expense – net in second-quarter 2005 includes a $13.1 million accrual for litigation contingencies.

The $118.8 million change from a segment profit to a segment loss is primarily due to the impact of cash flow hedge accounting. Also contributing to the decrease in segment profit is the absence in 2005 of realized and unrealized gains from the interest rate portfolio, which was liquidated in the fourth quarter of 2004. Additionally, segment profit includes estimated litigation accruals recorded in 2005.

Six months ended June 30, 2005 vs. six months ended June 30, 2004

The $564.2 million decrease in revenues includes a $713.9 million decrease in realized revenues, partially offset by a $149.7 million increase in net forward unrealized mark-to-market gains.

The $713.9 million decrease in realized revenues is primarily due to a $309 million decrease in power and natural gas realized revenues, the absence in 2005 of $387 million crude and refined products realized revenues and the absence in 2005 of an $18 million realized gain from the interest rate portfolio.

Power and natural gas realized revenues decreased primarily due to a 31 percent decrease in power sales volumes, partially offset by a nine percent increase in average power sales prices. Sales volumes decreased because Power did not replace certain long-term physical contracts that expired or were terminated. Further offsetting the decrease in power and natural gas realized revenues is a 13 percent increase in average natural gas sales prices. The absence of crude and refined products revenues is due to the sale of the refined products business in 2004. The absence of activity in the interest rate portfolio is due to the termination and liquidation of all remaining interest-rate derivatives in fourth-quarter 2004. In the first six months of 2004, an increase in interest rates caused a realized gain on interest rate derivatives.

The $149.7 million increase in net forward unrealized gains is primarily due to a $130 million increase associated with power and gas contracts and the absence in 2005 of the $18 million unrealized loss on the interest rate portfolio in 2004. The increase in power and gas primarily results from a greater increase in natural gas forward prices in 2005 than in 2004. Cash flow hedge accounting, which was prospectively applied to certain of Power's forecasted transactions beginning October 1, 2004, partially offsets the impact of natural gas price increases. Net unrealized gains of $227 million related to the effective portion of the hedges are reported in Accumulated other comprehensive loss in 2005. Also in 2005, Power recognized losses of $6.8 million representing a correction of unrealized losses associated with a prior year. The absence in 2005 of the unrealized loss on the interest rate portfolio is due to the termination and liquidation of all remaining interest-rate derivatives in fourth-quarter 2004. A decrease in forward interest rates caused unrealized losses in the interest rate portfolio in the first six months of 2004.

The $598.2 million decrease in Power's cost of sales is primarily due to a decrease in power and natural gas costs of $211 million and the absence in 2005 of $387 million of crude and refined products costs. Power and natural gas costs decreased primarily due to a 31 percent decrease in power purchase volumes, partially offset by a 14 percent increase in average power purchase prices and a 12 percent increase in average natural gas purchase prices. Costs in 2004 also reflect a $13 million payment made to terminate a non-derivative power sales contract. A 2004 reduction to certain contingent loss accruals of $10.4 million associated with power marketing activities in California during 2000 and 2001 partially offsets the decrease in costs. Crude and refined products costs decreased due to the sale of the refined products business in 2004.

SG&A expenses in 2004 include a $6 million reduction of allowance for bad debts resulting from a 2004 settlement with certain California utilities.

Other expense – net in 2005 includes a $13.1 million accrual for estimated litigation contingencies and a $4.6 million accrual for a regulatory settlement. Other expense – net in 2004 includes a $6.1 million charge related to the sale of certain receivables to a third party.

The $27.3 million increase in segment profit is primarily due to an increase in forward unrealized mark-to-market gains largely associated with larger increases in forward natural gas prices in the first half of 2005 compared to the same period in 2004. An accrual in 2005 for litigation contingencies partially offsets the increase in segment profit.

Gas Pipeline

Overview of six months ended June 30, 2005

Effective January 2005, Duke Energy Trading and Marketing, L.L.C. (Duke) terminated its firm transportation agreement related to Northwest Pipeline's Grays Harbor lateral. In January 2005, Duke paid Northwest Pipeline $94 million toward the contractually required termination payment. Duke and Northwest Pipeline have not agreed on the amount of the obligation. Northwest Pipeline's net book value of the related assets is $88 million. Northwest Pipeline has deferred the $6 million difference between the proceeds and net book value pending resolution of the disputed termination payment.

On June 16, 2005, we filed a Petition for a Declaratory Order at the Federal Energy Regulatory Commission ("FERC") requesting that FERC rule on our interpretation of Northwest Pipeline's tariff to aid in resolving the dispute with Duke. On July 15, 2005, Duke filed its motion to intervene and provided comments supporting its position concerning the issues in dispute. We anticipate that FERC will rule on Northwest Pipeline's petition sometime in 2005.

In February 2005, Gulfstream placed into service its 110-mile Phase II natural gas pipeline extension, expanding its reach across Florida and facilitating the increase of long-term firm service by 350 million cubic feet per day. In June 2005, Gulfstream commenced incremental natural gas transportation service of 400,000 dekatherms per day (DTH/d) for two major Florida utilities.

Operating results for the six months ended June 30, 2005 include approximately $13 million of credits to expenses, reflected as a $7 million reduction of Cost and operating expenses and a $6 million reduction of SG&A expenses, all of which were recorded in the first quarter. These credits are corrections of the carrying value of certain liabilities that were recorded in prior periods. Based on a review by management, these liabilities are no longer required and the reversal of amounts should have occurred in prior periods. Operating results for the three and six months ended June 30, 2005 reflect a $17.1 million reduction in pension expense to record the cumulative impact of a correction of an error attributable to the periods 2003 and 2004. The error was associated with our third-party actuarial computation of annual net periodic pension expense which resulted from the identification of errors in certain Transco participant data involving annuity contract information utilized for 2003 and 2004. Our management concluded that the effect of the previous accounting treatment is not material to prior periods, expected 2005 results or trend of earnings.

Outlook for the remainder of 2005

Central New Jersey Expansion Project

In February 2005, Transco received authorization from the FERC to construct and operate the Central New Jersey Expansion Project on its natural gas pipeline system. The expansion will provide an additional 105 Mdt/d of firm natural gas transportation service in Transco's northeastern market area. The estimated cost of the project is $16 million. The construction is expected to be placed into service in November 2005. The capacity has been fully subscribed by a single shipper for a twenty-year term.

Period-over-period results

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(Millions)		(Millions)	
Segment revenues	$357.0	$331.0	$692.3	$690.0
Segment profit	$164.5	$132.8	$331.9	$280.2

Management's Discussion and Analysis (Continued)

Three months ended June 30, 2005 vs. three months ended June 30, 2004

The $26 million, or eight percent, increase in Gas Pipeline revenues is due primarily to $32 million higher revenues associated with exchange imbalance settlements (offset in Costs and operating expenses). Partially offsetting this increase is $5 million lower non-reimbursable transportation revenues, which decreased primarily due to the termination of the Gray's Harbor contract, as previously discussed.

Costs and operating expenses increased $29 million, or 18 percent, due primarily to $32 million of higher costs associated with exchange imbalance settlements (offset in revenues) coupled with a $7 million increase in operating and maintenance (O&M) expense due to increased rental fees and slightly higher labor costs. Partially offsetting these increases is a $5 million decrease associated with adjustments to the carrying value of certain liabilities.

General and administrative costs decreased $22 million, or 77 percent, due primarily to a $17.1 million decrease in pension costs as previously discussed.

The $31.7 million, or 24 percent, increase in segment profit is primarily due to the $17.1 million decrease in pension costs as previously discussed, the absence of a 2004 $9 million write-off of previously capitalized costs incurred on an idled segment of Northwest Pipeline's system, which is included in Other expense – net, a $5 million decrease associated with adjustments to the carrying value of certain liabilities, and $3 million higher equity earnings related to our investment in Gulfstream associated with the service expansion noted previously.

Six months ended June 30, 2005 vs. six months ended June 30, 2004

The $2.3 million increase in Gas Pipeline revenues is due primarily to $28 million higher revenues associated with exchange imbalance settlements (offset in Costs and operating expenses). Partially offsetting this increase is $13 million lower revenues associated with reimbursable costs, which are passed through to customers (offset in Costs and operating expenses and SG&A expenses), and $14 million lower non-reimbursable transportation revenues due primarily to the termination of the Gray's Harbor contract, as previously discussed.

Costs and operating expenses increased $7 million, or two percent, due primarily to $28 million of higher costs associated with exchange imbalance settlements (offset in revenues) and $6 million in increased O&M expense due to increased rental fees and slightly higher labor costs. Partially offsetting these increases are the first-quarter reversal of $7 million of prior period accruals noted above, $6 million lower recovery of reimbursable costs, which are passed through to customers (offset in revenues), $5 million of lower operating taxes, and a $5 million decrease associated with second-quarter adjustments to the carrying value of certain liabilities.

General and administrative costs decreased approximately $36 million, or 59 percent, due to $17.1 million decrease in pension costs as previously discussed, $7 million lower reimbursable costs (offset in revenues), and a first-quarter reversal of $6 million of prior period accruals noted above.

The $51.7 million, or 18 percent, increase in segment profit is due primarily to the $17.1 million decrease in pension costs as previously discussed, a first-quarter reversal of $13 million of prior period accruals discussed above, the absence of a 2004 $9 million write-off of an idled segment of Northwest Pipeline's system, which is included in Other expense – net, and $11 million higher Gulfstream equity earnings. The increase in Gulfstream equity earnings is due to the realization of a $4.6 million construction fee award on the completion of the Phase II expansion project coupled with increased business associated with the Gulfstream service expansion noted previously.

Management's Discussion and Analysis (Continued)

Exploration & Production

Overview of six months ended June 30, 2005

Total average daily production for the six months ended June 30, 2005 is approximately 633 million cubic feet of gas equivalent (MMcfe) compared to 528 MMcfe for the same period in 2004. Our domestic average daily production volumes for the six months ended June 30, 2005 have increased 21 percent over the same period in 2004, increasing from 484 MMcfe to 586 MMcfe, respectively. The increase is directly related to our enhanced targeted drilling program, primarily within the Piceance basin. The sales of this production, along with higher net realized average prices, has resulted in overall increased revenue. Operating costs also increased as a result of servicing an increased number of producing wells completed in the last half of 2004 and the first six months of 2005. However, when compared on a per unit of production basis, these costs for the six months ended June 30,2005 have decreased by three cents per Mcfe over the same period in 2004.

During the second quarter of 2005, we acquired a 13,000 net acreage position, subject to final closing adjustments, in the Fort Worth basin in north-central Texas. Our entry into this basin allows us to own an operating position that has potential for significant growth. It increases our diversification into the Mid-continent region and allows us to utilize our horizontal drilling expertise to develop wells in the Barnett Shale formation.

Outlook for the remainder of 2005

Our expectations for the remainder of the year include the following.

- A continuing development drilling program in our key basins with increased activity in the Piceance and Powder River basins with associated planned capital expenditures projected in the range of approximately $300 million to $350 million for the remainder of 2005.
- Achieving a fifteen percent increase in average daily domestic production levels from the beginning of the year through the end of 2005.

Approximately 283 MMcfe per day of our remaining 2005 domestic production is hedged at prices that average $4.03 per MMcfe at a basin level. In addition, we have 50 MMcfe production per day hedged in NYMEX collar agreements that have an average floor price of $6.75 per MMcfe and an average ceiling price of $8.50 per MMcfe in effect from April 2005 through December 2005. Beginning in the fourth quarter of 2005, we will have an additional 50 MMcfe production per day hedged in Rockies collar agreements for the fourth quarter of 2005 that have an average floor price of $6.10 and an average ceiling price of $7.70. The Rockies collars will extend through 2006 and 2007.

In March 2005, we entered into a contract for the operation of ten new drilling rigs, each for a three year term. The additional rigs will allow us to accelerate our pace of development in the Piceance basin through both deployment of the additional rigs and also as a result of the drilling and operational efficiencies the rigs are designed to deliver. We expect to deploy one new rig each month, for ten months, beginning in November 2005.

Period-over-period results

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(Millions)		(Millions)	
Segment revenues	$281.5	$189.0	$530.5	$354.2
Segment profit	$118.3	$ 43.3	$222.0	$ 94.8

Three months ended June 30, 2005 vs. three months ended June 30, 2004

The $92.5 million, or 49 percent, increase in Exploration & Production revenues is primarily due to an $81 million increase in domestic production revenues reflecting higher production volumes and net realized average prices, which include the effect of hedge positions. The remainder of the increase primarily consists of $8 million higher revenues from gas management activities.

The increase in domestic production revenues reflects $53 million higher revenues associated with a 29 percent increase in net realized average prices for production sold and $28 million higher revenues associated with an 18 percent increase in average daily production volumes. The increase in production volumes primarily reflects an increase in the number of producing wells resulting from our successful drilling programs in the last part of 2004 and first two quarters of 2005. We expect production volumes to continue to increase for the remainder of 2005 as our development drilling program continues. The higher net realized average prices reflect the benefit of lower hedging levels than the prior period coupled with higher market prices for natural gas.

To manage the risk and volatility associated with the ownership of producing gas properties, we enter into derivative forward sales contracts, which economically lock in a price for a portion of our future production. During the second quarter of 2005, we hedged approximately 285 MMcfe per day of our production at prices that averaged $3.96 per MMcfe at a basin level. This compares to 387 MMcfe per day hedged at prices that averaged $3.58 at the basin level for the same period in 2004. In addition, during the second quarter of 2005 we had 50 MMcfe of production per day hedged in NYMEX collar arrangements that had an average floor price of $6.75 per MMcfe and an average ceiling price of $8.50 per MMcfe.

Total costs and expenses increased $18 million, primarily due to the following:

- $8 million higher gas management expenses primarily associated with increased gas management activities;
- $4 million higher general and administrative expenses primarily due to the absence in 2005 of an insurance recovery received in 2004, and increased staffing as a result of increased drilling and operational activity in 2005;
- $13 million higher depreciation, depletion and amortization expense, primarily due to higher production volumes and increased capitalized drilling costs; and
- $6 million higher operating taxes primarily as a result of increased market prices and production volumes sold.

These increases are partially offset by the absence in 2005 of an $11.3 million loss provision related to an ownership dispute on prior period production in the second quarter of 2004.

The $75 million increase in segment profit is due primarily to increased revenues from higher volumes and higher average prices, partially offset by higher expenses as discussed above.

Six months ended June 30, 2005 vs. six months ended June 30, 2004

The $176.3 million, or 50 percent, increase in Exploration & Production's revenues is primarily due to the $154 million higher domestic production revenues reflecting higher production volumes sold and higher net realized average prices. The remainder of the increase primarily consists of a $19 million increase in revenues from gas management activities and $3 million increased production revenues from our APCO Argentina operations.

The increase in domestic production revenues reflects $94 million higher revenues associated with a 27 percent increase in average daily net realized average prices for production sold and $60 million higher revenues associated with a 21 percent increase in average daily production volumes. The higher net realized average prices reflect the benefit of lower hedging levels than the prior period coupled with higher market prices for natural gas.

[Table of Contents](#)

Total costs and expenses increased $50 million**,** primarily due to the following:

- $19 million higher gas management expenses associated with the higher revenues from gas management activities;
- $7 million higher general and administrative expenses primarily due to the absence in 2005 of an insurance recovery received in 2004 and increased staffing as a result of increased drilling and operational activity in 2005;
- $29 million higher depreciation, depletion, and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;
- $5 million higher lease operating expense associated with the higher number of producing wells and an increase in well maintenance activities; and
- $11 million higher operating taxes primarily as a result of increased market prices and production volumes sold.

These increases are partially offset by the absence in 2005 of an $11.3 million loss provision related to an ownership dispute on prior period production in the second quarter of 2004 and a $7.9 million gain on the sale of an undeveloped leasehold position in Colorado in the first quarter of 2005.

The $127.2 million increase in segment profit is due primarily to increased revenues from higher volumes and higher average prices, partially offset by higher expenses as discussed above.

Management's Discussion and Analysis (Continued)

Midstream Gas & Liquids

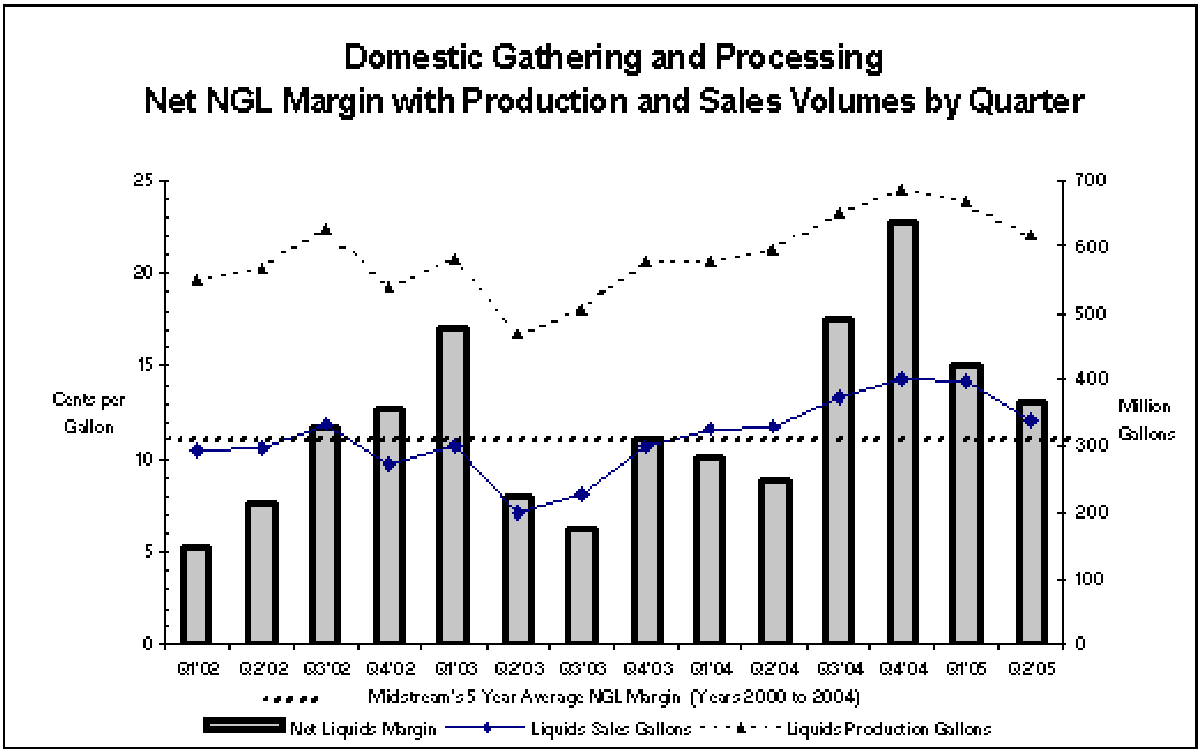
Overview of six months ended June 30, 2005

In 2005, 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.

On May 2, 2005, Williams Partners L.P. filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of five million common units, representing limited partnership interests in Williams Partners L.P., plus an option for the underwriters to purchase up to an additional 750,000 common units. On June 24, 2005, July 18, 2005, and August 3, 2005, Williams Partners L.P. filed amendments to the registration statement.

Williams Partners L.P. was formed to engage principally in the business of gathering, transporting and processing natural gas and fractionating and storing natural gas liquids. Williams Partners L.P. will own a 40 percent equity investment in the Discovery gathering, transportation, processing and NGL fractionation system; the Carbonate Trend sour gas gathering pipeline; three integrated NGL storage facilities near Conway, Kansas; and a 50 percent interest in an NGL fractionator near Conway, Kansas.

Despite a continued decline from the level realized in the second half of 2004, our natural gas liquids (NGL) per unit margins earned at our gas processing plants exceeded Midstream's historical five-year annual average in the first two quarters of 2005. This above-average level is largely the result of a significant increase in crude oil prices and an increased demand for petrochemical feedstocks such as ethane and propane. As indicated in the graph below, our quarterly margins exceeded the historical five-year annual average for the last four quarters. As a result of continued favorable NGL margins and high production volumes, our gas processing facilities produced improved financial results and operated at near capacity during the first half of 2005. Our olefins businesses also benefited from favorable commodity prices in the first half of 2005 as a result of additional demand for ethylene and propylene.



Management's Discussion and Analysis (Continued)

Outlook for the remainder of 2005

The following factors could impact our business in the remaining half of 2005 and beyond.

- As evidenced in recent years, natural gas and crude oil markets are highly volatile. Although NGL margins earned at our gas processing plants in the last four quarters were above Midstream's five-year average, these margins have been trending downward towards historical averages in 2005.
- Both gathering and NGL production volumes at our facilities are expected to be at or above levels of previous years due to continued strong drilling activities in our core basins. We also expect continued expansion of our gathering and processing systems in our West region to keep pace with increased demand for our services.
- After three favorable quarters, our olefins margins fell in the second quarter of 2005 as a result of declining demand and rising inventories. We believe olefins margins will improve later in 2005 as a result of expected inventory declines due to lower industry production levels and anticipated stronger demand. Additionally, a fire at a Canadian oil sands facility that supplies us with off-gas feedstock reduced our throughput in the first half of 2005. We expect throughput levels at our Canadian olefins facilities to return to normal in the fourth quarter of 2005. We are pursuing a business interruption claim with our insurance carrier. We have not recognized any amounts related to this pending claim.
- As disclosed in the Critical accounting policies & estimates section of our 2004 Annual Report on Form 10-K, it is possible that our investment in our Canadian olefins assets may not be recoverable without modification to or a renegotiation of key terms in an off-gas processing agreement. We are evaluating our alternatives and will continue to monitor the recoverability of our investment.
- We expect additional revenues from our Devils Tower facilities in late 2005 as completed wells in the Triton and Goldfinger prospects begin to flow new production volumes.
- 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 closed the sale of our Gulf Liquids refinery off-gas business in Louisiana on July 15, 2005. This will result in lower revenues and expenses, but should not have a material impact on Midstream segment profit.

Period-over-period results

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(Millions)		(Millions)	
Segment revenues	$780.1	$633.7	$1,587.1	$1,265.5
Segment profit				
Domestic Gathering & Processing	$ 98.4	86.8	198.6	177.1
Venezuela	24.2	20.0	46.2	41.9
Other	.4	4.7	22.4	16.2
Unallocated general and administrative expense	(13.9)	(13.0)	(29.5)	(26.6)
Total	$109.1	$ 98.5	$ 237.7	$ 208.6

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" above. These charges represent any overhead cost not directly attributable to one of the specific asset groups noted in this discussion. All periods presented reflect this change.

Three months ended June 30, 2005 vs. three months ended June 30, 2004

The $146.4 million increase in Midstream's revenues is due primarily to favorable commodity prices and higher sales volumes related to our gas processing business and higher crude sales volumes. Revenues associated with production of NGLs increased $50 million, of which $44 million is due to higher NGL prices and $6 million is due to higher volumes. Crude marketing revenues increased $59 million as a result of the start up of a deepwater pipeline in the second quarter of 2004, while revenues associated with the marketing of NGLs increased approximately $52 million as a result of both higher prices and additional spot sales. These higher revenues were partially offset by $11 million in lower olefins sales due to reduced volumes.

Costs and operating expenses increased $133 million primarily in support of higher sales noted above. A significant component of this increase is $33 million in higher costs related to the increased production of NGLs. Approximately $26 million of this increase is due to higher natural gas prices while $7 million is the result of higher natural gas purchase volumes. Similar to the impact to revenues, total costs and operating expenses also increased $59 million due to higher crude marketing purchases and $52 million related to the marketing of NGLs. These higher costs are partially offset by $12 million in lower olefins production expenses.

The $10.6 million increase in Midstream segment profit is primarily due to higher net NGL margins and higher gathering and processing revenues, partially offset by lower deepwater production handling revenues. A more detailed analysis of segment profit of Midstream's various operations is presented below.

Domestic Gathering & Processing: The $11.6 million increase in domestic gathering and processing segment profit includes a $22 million increase in the West region, partially offset by a $10 million decrease in the Gulf Coast region.

The $22 million increase in our West region's segment profit primarily resulted from higher net NGL margins, higher gathering and processing volumes, and lower operating expenses. The significant drivers to these items are as follows.

- Net NGL margins increased $8 million compared to the second quarter of 2004. This increase was driven by a 46 percent increase in average per unit NGL margins, which more than offset a slight decline in sales volumes. The decline in NGL sales volumes was due in part to more customers electing the fee-based billing option of gas processing contracts.
- Gathering and processing fee revenues increased $7 million primarily as a result of higher volumes due to increased drilling activity in the New Mexico and Rocky Mountain production areas. A portion of this increase is also due to an increase in volumes subject to fee-based processing contracts in the Wyoming area.
- Operating expenses were $2 million favorable in part due to lower maintenance project spending at our Wyoming facilities.

The $10 million decrease in our Gulf Coast region's segment profit is impacted by a correction to our revenue recognition methodology for Devils Tower in 2004. The third-quarter 2004 correction resulted in the deferral to future periods of $16.5 million of revenues recognized in the second quarter of 2004. Devils Tower cash flows were not affected by this adjustment. Partially offsetting this correction is $7 million related to higher net NGL margins and production handling revenues partially offset by increased operating expenses. The significant components of the segment profit changes include the following.

- Net NGL margins at our Gulf Coast gas processing plants increased $8 million. A 78 percent increase in per unit margins comprised $6 million of the increase while a 36 percent increase in volumes comprised the remaining $2 million increase.
- Segment profit from our deepwater assets decreased $15 million largely as a result of the $16.5 million negative impact of the revenue recognition correction mentioned above. The impact of this correction is partially offset by higher production volumes related to our production handling facilities.
- These increases are partially offset by $3 million in higher maintenance expense primarily due to additional projects at our Mobile Bay plant and gathering areas.

Venezuela: Segment profit for our Venezuela assets for the second quarter of 2005 increased $4.2 million as a result of higher plant volumes and higher equity earnings from our investment in the ACCROVEN partnership largely due to the renegotiation of a power supply contract.

Other: The $4.3 million decrease in segment profit in our other operations is largely due to the absence of $2 million of segment profit related to the ethylene distribution system sold in October 2004.

Six months ended June 30, 2005 vs. six months ended June 30, 2004

The $321.6 million increase in Midstream's revenues is largely due to favorable commodity prices and higher sales volumes related to our gas processing business. Revenues associated with production of NGLs increased $139 million, of which $90 million is due to higher NGL prices and $49 million is due to higher volumes. Crude marketing revenues increased $121 million as a result of the start up of a deepwater pipeline in the second quarter of 2004 while the marketing of NGLs increased $75 million as a result of both higher prices and additional spot sales. These increases were partially offset by $5 million in lower olefins product sales.

Costs and operating expenses increased $290 million primarily in support of higher sales noted above. Costs related to the production of NGLs increased $96 million mainly as a result of $87 million in higher natural gas purchases due to increased volumes and higher prices. In addition, operating expenses increased $14 million mostly due to higher maintenance costs. Similar to the impact to revenues, total costs and operating expenses also increased $121 million due to higher crude marketing purchases and $75 million related to the marketing of NGLs. These increases are partially offset by $16 million in lower olefins cost of goods sold.

The $29.1 million increase in Midstream segment profit is primarily due to higher net NGL margins and higher gathering and processing revenues, partially offset by lower deepwater production handling revenues and higher operating expenses. A more detailed analysis of segment profit of Midstream's various operations is presented below.

Domestic Gathering & Processing: The $21.5 million increase in domestic gathering and processing segment profit includes a $40 million increase in the West region, partially offset by an $19 million decrease in the Gulf Coast region.

The $40 million increase in our West region's segment profit primarily resulted from higher net NGL margins and higher gathering and processing revenues. The significant components of this increase are as follows.

- Net NGL margins increased $29 million compared to the first half of 2004. Average per unit NGL margins increased 53 percent and comprised $26 million of the increase while volumes increased seven percent and comprised the remaining $3 million increase.

- Gathering and processing fee revenues increased $10 million primarily as a result of higher volumes due to increased drilling activity in the New Mexico and Rocky Mountain production areas. A portion of this increase is also due to the increase in volumes subject to fee-based processing contracts in the Wyoming area.

The $19 million decrease in our Gulf Coast region's segment profit includes the $16.5 million negative impact related to the 2004 revenue recognition correction previously mentioned. The remaining decline of $3 million is a result of higher operating expenses partially offset by higher net NGL margins. The significant components of this decline include the following.

- Segment profit from our Gulf gathering assets declined $7 million primarily due to higher maintenance expenses.
- Segment profit from our deepwater assets decreased $19 million, which includes the $16.5 million negative impact of the revenue recognition correction mentioned above. The remaining $3 million decrease is the result of lower revenues at our Canyon Station production handling facility partially offset by higher production volumes related to the Devils Tower assets placed into service in the second quarter of 2004. The Canyon Station revenue decrease was due in part to a leak on a customer's gas gathering line that delivers production to our facility. This leak was repaired during the first quarter of 2005.
- These declines were partially offset by $8 million in higher segment profit from our Gulf processing plants. The increase is primarily due to $14 million in higher NGL margins due to a 47 percent increase in per unit margins and a 25 percent increase in volumes. The favorable NGL margins are partially offset by the absence of a $3 million favorable 2004 measurement liability settlement and $2 million in higher maintenance spending.

Venezuela: Segment profit for our Venezuela assets increased $4.3 million as a result of higher plant volumes and higher equity earnings from our investment in the ACCROVEN partnership largely due to the renegotiation of a power supply contract.

Other: The $6.2 million increase in segment profit in our other operations is largely due to $11 million in higher net olefins margins, $2 million in higher storage revenues, partially offset by the absence of $5 million in net profits related to the ethylene distribution system sold in October 2004.

Unallocated general and administrative expense: The $2.9 million increase in unallocated general and administrative expense is primarily due to higher professional and legal fees and higher personnel costs.

Other

Overview of the six months ended June 30, 2005

We reported in our 2004 Annual Report on Form 10-K that we expected improved results from our investment in Longhorn. A key indicator of performance of the pipeline is product shipping volumes following the initial commissioning of the pipeline at the end of 2004. While shipping volumes during the first quarter of 2005 were lower than planned, volumes were increasing and expectations for the year were unchanged. However, in the second quarter of 2005, shipping volumes declined significantly from those experienced in the first quarter, reflecting the impact of significant changes in transportation pricing competition and economics in the wake of higher crude oil prices. Longhorn management has indicated that the shortfall in volumes is likely to continue and that continued operation as originally planned is no longer economically feasible. As a result, the owners and management of Longhorn are currently considering various alternative business strategies for the pipeline.

Due to these events, we evaluated our investment in Longhorn to determine if there has been an other-than-temporary decline in the fair value. Given the likelihood of continued losses under the current situation and Longhorn’s assessment of the need for a strategic change, we believe the investment is impaired and the decline is other than temporary. Our management has estimated the fair value of our investment in Longhorn based on its assessment of the probability of, and discounted future cash flows from, the scenarios currently under consideration. Based on this assessment, we have recorded an impairment of $49.1 million, resulting in a remaining net book value of $51.4 million. We will continue to consider the strategic scenarios and reassess the estimate of our fair value in Longhorn following Longhorn management’s finalization of a strategic alternative, which may result in a significant additional impairment in a future period. We expect a decision on the future operation of the Longhorn pipeline by the end of 2005.

Period-over-period results

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(Millions)		(Millions)	
Segment revenues	$ 6.1	$ 7.0	$ 13.1	$ 19.6
Segment loss	$(60.5)	$(14.3)	$(64.6)	$(23.0)

Other segment loss for the three and six months ended June 30, 2005, includes $6.7 million and $12.2 million, respectively, of equity losses related to our investment in Longhorn. We expect to incur additional future equity losses from Longhorn in 2005 due to the circumstances described above. Other segment loss for the three and six months ended June 30, 2005, includes a $49.1 million impairment of our investment in Longhorn and a related $4 million write-off of capitalized project costs.

On April 1, 2005, we completed a contract to transfer our Longhorn operating agreement to a new operator in exchange for payments of approximately $285,000 a month, adjusted for inflation, over the next seven years. The transfer became effective May 1, 2005. The realization of these payments is dependent upon the continued operation of Longhorn.

Other segment loss for the three and six months ended June 30, 2004, includes a $10.8 million impairment of our investment in Longhorn. The charge reflected management’s belief that there was an other-than-temporary decline in the fair value of this investment following a determination that additional funding would be required to commission the pipeline into service. Other segment loss for the six months ended June 30, 2004, also includes $6.5 million net unreimbursed advisory fees related to the recapitalization of Longhorn in February 2004. If the project achieves certain future performance measures, the unreimbursed fees may be recovered. As a result of this recapitalization, we sold a portion of our equity investment in Longhorn for $11.4 million, received $58 million in repayment of a portion of our advances to Longhorn and converted the remaining advances, including accrued interest, into preferred equity interests in Longhorn. These preferred equity interests are subordinate to the preferred interests held by the new investors. Other than the unreimbursed fees, no gain or loss was recognized on this transaction.

Fair value of trading and non-trading derivatives

The table below reflects the fair value of derivatives held for trading purposes as of June 30, 2005. We present the fair value of assets and liabilities by the period in which we expect them to be realized.

Net Assets (Liabilities)
(Millions)

To be Realized in 1—12 Months (Year 1)	To be Realized in 13—36 Months (Years 2—3)	To be Realized in 36—60 Months (Years 4—5)	To be Realized in 61—120 Months (Years 6—10)	Net Fair Value
$(13)	$ (4)	$ —	$ —	$ (17)

As the table above illustrates, we are not materially engaged in trading activities. However, we hold a substantial portfolio of non-trading derivative contracts. Non-trading derivative contracts are those that hedge or could possibly hedge on an economic basis forecasted transactions associated with Power's long-term structured contract position and owned generation, Exploration & Production's forecasted sales of natural gas production, as well as the activities of our other segments. As a result of our decision to retain the Power business, in the fourth quarter of 2004, we designated a portion of the existing derivatives as SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," (SFAS 133) cash flow hedges. Many of these non-trading derivatives had an existing fair value prior to their designation as cash flow hedges. Certain other of Power's derivatives have not been designated as, or do not qualify as, SFAS 133 hedges. We also hold certain derivative contracts, which also qualify as SFAS 133 cash flow hedges, that primarily hedge Exploration & Production's forecasted natural gas sales. The table below reflects the fair value of derivatives held for non-trading purposes as of June 30, 2005. Of the total fair value of non-trading derivatives, SFAS 133 cash flow hedges have a net asset value of $124.4 million as of June 30, 2005, which includes the fair value of the derivatives upon their designation as SFAS 133 cash flow hedges.

Net Assets (Liabilities)
(Millions)

To be Realized in 1—12 Months (Year 1)	To be Realized in 13—36 Months (Years 2—3)	To be Realized in 36—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
$ —	$ 90	$ 151	$ 39	$ 5	$ 285

Counterparty credit considerations

We include an assessment of the risk of counterparty non-performance 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 to which the contract is subject 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 June 30, 2005, we hold collateral support of $434 million. We also enter into netting agreements to mitigate counterparty performance and credit risk.

Management's Discussion and Analysis (Continued)

The gross credit exposure from our derivative contracts as of June 30, 2005 is summarized below.

Counterparty Type	Investment Grade (a)	Total
	(Millions)	
Gas and electric utilities	$ 705.6	$ 749.0
Energy marketers and traders	1,475.7	4,471.8
Financial institutions	2,867.1	2,868.9
Other	1.3	14.5
	$5,049.7	8,104.2
Credit reserves		(30.3)
Gross credit exposure from derivatives		$8,073.9

We assess our credit exposure on a net basis. The net credit exposure from our derivatives as of June 30, 2005 is summarized below.

Counterparty Type	Investment Grade (a)	Total
	(Millions)	
Gas and electric utilities	$162.8	$ 179.9
Energy marketers and traders	329.7	671.8
Financial institutions	148.6	148.6
Other	1.3	1.8
	$642.4	$1,002.1
Credit reserves		(30.3)
Net credit exposure from derivatives(b)		$ 971.8

(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.

(b) One counterparty within the California power market represents more than ten percent of the derivative assets and is included in investment grade. Standard & Poor's and Moody's Investors Service do not currently rate this counterparty. We included this counterparty in the investment grade column based upon contractual credit requirements.

Financial condition and liquidity

Liquidity

Overview

In January, we retired $200 million of 6.125 percent notes which matured January 15, 2005. On February 16, 2005, the holders of the remaining 10.9 million equity forward contracts associated with the FELINE PACS units exercised contracts to purchase one share of our common stock for $25 a share, resulting in cash proceeds of approximately $273 million. The remaining notes associated with the FELINE PACS units totaling approximately $73 million are due February 16, 2007.

In January 2005, our two unsecured revolving credit facilities were terminated and replaced with two new facilities. The two new facilities do not include most of the restrictive covenants of the previous two facilities, including the fixed charge coverage ratio. The new facilities also no longer limit quarterly dividends, asset sales, investments, and the incurrence of additional indebtedness and issuance of disqualified stock.

During May 2005, we amended and restated our $1.275 billion secured revolving and letter of credit agreement, resulting in certain changes, including the following:

- added Williams Partners L.P. as a borrower for up to $75 million;
- provided our guarantee for obligations of Williams Partners L.P.;
- released certain Midstream assets held as collateral and replaced them with the common stock of Transco; and
- reduced commitment fees and margins.

Sources of liquidity

Our liquidity is derived from both internal and external sources. Certain of those sources are available to us (at the parent level) and others are available to certain of our subsidiaries.

At June 30, 2005, we have the following sources of liquidity from cash and cash equivalents:

- cash-equivalent investments at the corporate level of $989 million as compared to $735 million at December 31, 2004; and
- cash and cash-equivalent investments of various international and domestic entities of $308 million, as compared to $195 million at December 31, 2004.

We also have approximately $55 million in action rate securities, which are not classified as cash equivalents but which are also a source of liquidity.

At June 30, 2005, we have capacity of $17 million available under our two unsecured revolving credit facilities totaling $500 million, compared to $28 million at December 31, 2004. These facilities provide for both borrowings and letters of credit, but are used primarily for issuing letters of credit.

At June 30, 2005, we also have capacity of $744 million available under our $1.275 billion secured revolving credit facility compared to $853 million at December 31, 2004. As discussed above, the facility is secured by the common stock of Transco and guaranteed by Williams Gas Pipeline Company, L.L.C., the parent company of Transco and Northwest Pipeline. Transco and Northwest Pipeline each has access to $400 million under this facility, and Williams Partners L.P. has access to $75 million, but in all cases only to the extent that sufficient amounts remain unborrowed by us or by one of the other two borrowers under the facility. We provided a guarantee for obligations of Williams Partners L.P. under this facility.

We have an effective shelf registration statement with the Securities and Exchange Commission that authorizes us to issue an additional $2.2 billion of a variety of debt and equity securities. In addition, our wholly owned subsidiaries, Northwest Pipeline and Transco, also have outstanding registration statements filed with approximately $350 million of aggregate availability remaining under these shelf registration statements at June 30, 2005. The ability of Northwest Pipeline to utilize these registration statements for debt securities is restricted by certain covenants of its debt agreements. Interest rates, market conditions, and industry conditions will affect amounts raised, if any, in the capital markets.

During the first six months of 2005, we satisfied liquidity needs with:

- $793.3 million in cash generated from cash flows of continuing operating activities;
- approximately $273 million proceeds from the issuance of 10.9 million shares of common stock purchased under the FELINE PACS equity forward contracts;
- approximately $87.9 million from a contract termination payment; and
- approximately $54.7 million proceeds from the sale of the WilTel Note.

Credit ratings

One of our objectives for 2005 is to continue the improvement in our financial ratios, with the goal of achieving ratios comparable to investment grade rated companies. If the improvement in our ratios continues, our credit ratings may improve. However, a decline in our financial ratios, or other adverse events, could result in a ratings decline.

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

In January 2005, we terminated our two unsecured revolving credit facilities totaling $500 million and replaced them with two new facilities that contain similar terms but fewer restrictions (see Note 10 of Notes to the Consolidated Financial Statements).

As previously discussed, we have provided a guarantee for obligations of Williams Partners L.P. under the $1.275 billion secured revolving credit facility.

We have various guarantees which are disclosed in Note 12 of Notes to Consolidated Financial Statements. We do not believe these guarantees, or the possible fulfillment of them, will negatively impact our liquidity.

Operating activities

The improvement in cash flow from continuing operating activities in 2005 is due primarily to an increase in Income from continuing operations, resulting from higher gas production volumes and net average realized prices for production sold. The improvement is also due to a decrease in interest payments due to lower average borrowing levels.

For the six months ended June 30, 2005, we recorded approximately $53.5 million in Provision for loss on investments, property and other assets consisting primarily of a $49.1 million impairment of our investment in Longhorn.

For the six months ended June 30, 2005, we recorded $74.6 million in cash receipts from changes in margins compared to $146 million for the six months ended June 30, 2004. The decrease is due to a decrease in letters of credit issued. In 2004, our Power subsidiary issued letters of credit to replace its cash margin deposits. As the letters of credit were issued, the counterparties returned our cash margin deposits to us. We have not issued as many letters of credit in 2005.

For the six months ended June 30, 2004, we recorded approximately $30 million in Provision for loss on investments, property and other assets consisting primarily of a $10.8 million impairment of our investment in Longhorn and a $9 million write-off of previously-capitalized costs incurred on an idled segment of Northwest Pipeline's system.

In the first quarter of 2004, we recognized net cash used by operating activities of discontinued operations in the Consolidated Statement of Cash Flows of $52.9 million. Included in this amount was approximately $70 million in use of funds related to the timing of settling working capital issues of the Alaska refinery and related assets. In the second quarter of 2004, we received the proceeds from the collection of approximately $58 million in trade receivables related to the Alaska refinery and related assets.

Financing activities

In the first quarter of 2005, our Transco subsidiary retired $200 million of 6.125 percent unsecured notes due January 15, 2005.

As discussed above, 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.

In the first quarter of 2004, we retired the remaining $679 million outstanding balance of the 9.25 percent senior unsecured notes due March 15, 2004.

In June 2004, we retired approximately $1.17 billion of our outstanding notes and debentures through a tender offer. The payment of these notes and debentures in second-quarter 2004 is recorded as Payments of long term debt on the Consolidated Statement of Cash Flows. In May 2004, we also repurchased on the open market approximately $255 million of various notes. In conjunction with the tendered notes, related consents, and the debt repurchase, we paid premiums of approximately $79 million. The premiums, as well as related fees and expenses, together totaling $96.8 million, were recorded in Early debt retirement costs.

In June 2004, we made a payment of approximately $109 million for accrued interest, short-term payables, and long-term debt on borrowings collateralized by certain receivables from the California Power Exchange that were previously sold to a third party. Approximately $79 million of the payment is included in Payments of long-term debt on the Consolidated Statement of Cash Flows.

Dividends paid on common stock were $.05 per common share on a quarterly basis and totaled $57.1 million for the six months ended June 30, 2005. On July 20, 2005, we increased the quarterly dividend to $.075 per common share, which will result in future quarterly dividends of approximately $43 million at the current level of common shares outstanding. For the six months ended June 30, 2004, dividends paid on common stock were $.01 per share on a quarterly basis and totaled $10.4 million. A covenant under our former $500 million revolving credit facilities limited our quarterly common stock dividends to not more than $.05 per common share. The covenant was removed when the facilities were terminated and replaced on January 20, 2005.

Investing activities

During the first six months of 2005, capital expenditures totaled approximately $516.6 million and were primarily related to our Exploration & Production segment's drilling program, mostly in the Piceance basin.

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

In March 2005, we recorded an $87.9 million contract termination payment received by Northwest Pipeline. Northwest Pipeline entered into a contract to build a pipeline and supply gas to a proposed power plant. The customer subsequently terminated the contract and thus was required to reimburse Northwest Pipeline for the net book value of the pipeline.

At June 30, 2005, we have $55 million of auction rate securities. These securities are included in Other current assets and deferred charges on our Consolidated Balance Sheet. Due primarily to the monthly bidding process, our Consolidated Statement of Cash Flows includes $155.3 million of Purchases of auction rate securities and $100.3 million of Proceeds from sales of auction rate securities.

In June 2005, our Midstream subsidiary sold their remaining interests in Mid-American Pipeline and Seminole Pipeline for approximately $25 million.

In April 2005, our Midstream subsidiary made an additional investment of $35 million in Discovery Pipeline.

During the first four months of 2004, we purchased $471.8 million of restricted investments comprised of U.S. Treasury notes and received proceeds of $851.4 million on the scheduled maturity of certain of this type investment. We made these purchases to satisfy the 105 percent cash collateralization requirement in our $800 million revolving credit facility. The facility was terminated on May 3, 2004, after we obtained the $1 billion secured revolving credit facility, which was subsequently amended in August 2004 to the current level of $1.275 billion.

During February 2004, we participated in a recapitalization plan completed by Longhorn. As a result of this plan, we received approximately $58 million in repayment of a portion of our advances to and deferred payments from Longhorn and converted the remaining advances, including accrued interest, into subordinated equity interests in Longhorn. The $58 million received is included in Proceeds from dispositions of investments and other assets.

In the first half of 2004, we received $304 million in proceeds from the sale of the Alaska refinery, retail and pipeline and related assets.

Contractual obligations

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2004, we had certain contractual obligations at December 31, 2004, with various maturity dates, related to the following:

- long-term debt;
- operating leases;
- purchase obligations; and
- other long-term liabilities, including physical and financial derivatives.

During the first six months of 2005, the amount of our contractual obligations changed significantly due to the following.

- During the first six months of 2005, the fair value of Power's physical and financial derivatives decreased by approximately $15 million. The decrease is due primarily to normal trading and market activity.
- In March 2005, we entered into a contract for the operation of ten newly constructed drilling rigs, with each rig carrying a three-year commitment. Expected delivery of the first rig is November 2005, then one rig per month for the next nine months. The minimum contractual obligation at June 30, 2005, is $104 million associated with early termination penalties of $10.4 million per rig. The base amount of payments over the life of the contract is $192 million, and could increase to $230 million if all performance incentives are earned.

Outlook for 2005 and beyond

We entered 2005 positioned for growth through disciplined investments in natural gas businesses. During 2005, we expect to maintain liquidity from cash and revolving credit facilities of at least $1 billion. We are maintaining this level as we consider the potential impact of significant changes in commodity prices, contract margin requirements above current levels, unplanned capital spending needs and the need to meet near term scheduled debt payments. Scheduled debt maturities for the remainder of 2005 and for 2006 total approximately $146 million.

The additional rigs contracted for in March 2005 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 drilling and operational efficiencies the rigs are designed to deliver. Beginning in November 2005, we expect to deploy one new rig each month. As a result, we have increased our planned capital spending for Exploration & Production by $30 million in 2005 and $200 million in both 2006 and 2007.

We estimate capital and investment expenditures will total approximately $1.1 billion to $1.3 billion in 2005, with approximately $600 million to $800 million to be incurred over the next six months. Of the estimated capital expenditures for 2005, approximately $610 million to $695 million is for maintenance related projects primarily at Gas Pipeline, including pipeline replacement and Clean Air Act projects. We expect to fund capital and investment expenditures, debt payments, and working-capital requirements through cash and cash equivalents on hand and cash generated from operations, which is currently estimated to be between $1.15 billion and $1.45 billion in 2005.

On May 2, 2005, Williams Partners L.P. filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of five million common units, representing limited partnership interests in Williams Partners L.P., plus an option for the underwriters to purchase up to an additional 750,000 common units. On June 24, 2005, July 18, 2005, and August 3, 2005, Williams Partners L.P. filed amendments to the registration statement.

We have reached a preliminary settlement with the Internal Revenue Service relating to an outstanding tax issue associated with prior years. As a result of the preliminary settlement, we expect to make payments totaling approximately $180 million to $200 million in the last half of 2005, all of which is accrued at June 30, 2005. The expected settlement will be subject to the approval of the Joint Committee on Taxation.

Based on our available cash on hand and expected cash flows from operations, we believe we have, or have access to, the financial resources and liquidity necessary to meet future cash requirements and maintain a sufficient level of liquidity to reasonably protect against unforeseen circumstances requiring the use of funds.

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 half of 2005.

Commodity price risk

We are exposed to the impact of market fluctuations in the price of natural gas, power, crude oil, refined products and natural gas liquids as well as other market factors, such as market volatility and commodity price correlations, including correlations between crude oil and gas prices and 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. 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 non-trading 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 non-derivative energy contracts have been excluded from our estimation of value at risk.

Trading

Our trading portfolio consists of derivative contracts entered into to provide price risk management services to third-party customers. Only contracts that meet the definition of a derivative are carried at fair value on the balance sheet. Our value at risk for contracts held for trading purposes was approximately $2 million at June 30, 2005, and $1 million at December 31, 2004.

Non-trading

Our non-trading 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 • Electricity purchases • Electricity sales

The value at risk for contracts held for non-trading purposes was $28 million at June 30, 2005, and $29 million at December 31, 2004. Certain of the contracts held for non-trading 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 non-trading portfolio that includes the underlying commodity positions.

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 15(d) — (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.

Second-Quarter 2005 Changes in Internal Controls Over Financial Reporting

On May 1, 2005, we completed the second of a series of systems implementations which are part of an enterprise initiative to move to common enterprise accounting systems. The implementation on May 1, 2005, impacted our Gas Pipeline business segment and represented a replacement of the primary accounting systems used to process, accumulate and summarize accounting information. As a result, some processes and related controls were modified to address any changes resulting from the system implementation.

Other than as described above, there have been no material changes in our Internal Controls over financial reporting during the second quarter.

Table of Contents

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information called for by this item is provided in Note 12 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 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 4. Submission of Matters to a Vote of Security Holders

At our Annual Meeting of Stockholders held on May 19, 2005, four individuals were elected to serve as directors and six individuals continue to serve as directors pursuant to their prior elections. Those directors continuing in office are William E. Green, W. R. Howell, Charles M. Lillis, George A. Lorch, William G. Lowrie, and Joseph H. Williams. The appointment of Ernst & Young LLP as our independent auditor for 2005 was ratified and a stockholder proposal regarding a majority vote standard for board elections was not approved.

A tabulation of the voting at the Annual Meeting with respect to the matters indicated is as follows:

Election of Directors

Name	For	Withheld
Juanita H. Hinshaw	518,114,656	11,094,532
Frank T. MacInnis	517,711,280	11,497,908
Steven J. Malcolm	514,323,932	14,885,256
Janice D. Stoney	517,292,435	11,916,753

Ratification of Appointment of Independent Auditors

For	Against	Abstain
511,773,795	13,531,018	3,904,375

Stockholder Proposal for a Majority Vote Standard for Board Elections

For	Against	Abstain	Broker Non-Votes
178,780,197	184,640,328	6,414,025	159,374,638

Item 5. Other Information

On May 19, 2005, our Board of Directors increased the board committee chairmen and presiding director retainers to the following:

Nominating and Governance Committee Chairman retainer	$10,000
Finance Committee Chairman retainer	$10,000
Audit Committee Chairman retainer	$15,000
Presiding Director retainer	$20,000

Item 6. Exhibits

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

Exhibit 1.1 — Amended and Restated Credit Agreement dated as of May 20, 2005 among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, and the Banks, Citibank, N.A. and Bank of America, N.A. (each an "Issuing Bank"), and Citicorp USA, Inc. as administrative agent (filed as Exhibit 1.1 to Form 8-K filed May 26, 2005).

Exhibit 12 — Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements.

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.

Table of Contents

SIGNATURE

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

THE WILLIAMS COMPANIES, INC.
(Registrant)

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

August 4, 2005

Exhibit 12

The Williams Companies, Inc.
Computation of Ratio of Earnings to Fixed Charges
(Dollars in millions)

	Six months ended June 30, 2005
Earnings:	
Income from continuing operations before income taxes	$414.1
Minority interest in income of consolidated subsidiaries	10.0
Less: Equity earnings	(27.5)
Income from continuing operations before income taxes, minority interest in income of consolidated subsidiaries and equity earnings	396.6
Add:	
Fixed charges:	
Interest accrued, including proportionate share from equity-method investees	338.8
Rental expense representative of interest factor	9.7
Total fixed charges	348.5
Distributed income of equity investees	44.1
Less:	
Capitalized interest	(2.5)
Total earnings as adjusted	$786.7
Fixed charges	$348.5
Ratio of earnings to fixed charges	2.26

Exhibit 31.1

SECTION 302 CERTIFICATION

I, Steven J. Malcolm, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Williams Companies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2005

/s/ Steven J. Malcolm
Steven J. Malcolm
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

SECTION 302 CERTIFICATION

I, Donald R. Chappel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Williams Companies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 4, 2005

/s/ Donald R. Chappel

Donald R. Chappel
Senior Vice President and Chief Financial Officer
(Principal Executive Officer)

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of The Williams Companies, Inc. (the “Company”) on Form 10-Q for the period ending June 30, 2005 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned hereby certifies, in his capacity as an officer of the Company, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Steven J. Malcolm
Steven J. Malcolm
Chief Executive Officer
August 4, 2005

/s/ Donald R. Chappel
Donald R. Chappel
Chief Financial Officer
August 4, 2005

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.