UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2004

OR

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

For the transition period from __________ to __________

Commission file number 1-4174

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 (X) No ( )

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

Yes (X) No ( )

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

Class	Outstanding at October 31, 2004
Common Stock, $1 par value	556,451,634 Shares

The Williams Companies, Inc.

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Certain matters discussed in this report, excluding historical information, include forward-looking statements — statements that discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

Forward-looking statements can be identified by 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 2003 Form 10-K as restated and amended.

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The Williams Companies, Inc.

Consolidated Statements of Operations
(Unaudited)

(Dollars in millions, except per-share amounts)	Three months ended September 30, 2004	Three months ended September 30, 2003*	Nine months ended September 30, 2004	Nine months ended September 30, 2003*
Revenues:				
Power	$ 2,604.2	$ 3,888.4	$ 7,233.8	$10,610.1
Gas Pipeline	321.0	334.0	1,011.0	1,004.3
Exploration & Production	209.3	168.7	563.5	612.8
Midstream Gas & Liquids	746.4	701.8	2,004.2	2,069.4
Other	6.7	11.0	26.3	59.1
Intercompany eliminations	(514.8)	(360.5)	(1,351.8)	(1,223.9)
Total revenues	3,372.8	4,743.4	9,487.0	13,131.8
Segment costs and expenses:				
Costs and operating expenses	2,854.5	4,387.6	8,202.7	11,836.0
Selling, general and administrative expenses	87.9	96.1	254.2	317.1
Other (income) expense - net	(4.8)	(24.8)	26.6	(249.4)
Total segment costs and expenses	2,937.6	4,458.9	8,483.5	11,903.7
General corporate expenses	24.2	17.8	84.5	62.5
Operating income (loss):				
Power	124.2	21.7	137.3	255.9
Gas Pipeline	137.4	135.5	409.6	397.4
Exploration & Production	67.5	56.3	156.2	344.2
Midstream Gas & Liquids	103.6	66.3	303.3	233.3
Other	2.5	4.7	(2.9)	(2.7)
General corporate expenses	(24.2)	(17.8)	(84.5)	(62.5)
Total operating income	411.0	266.7	919.0	1,165.6
Interest accrued	(197.3)	(276.3)	(662.9)	(1,035.0)
Interest capitalized	1.0	11.4	5.7	34.6
Interest rate swap income (loss)	(4.0)	2.5	(5.3)	(6.4)
Investing income	9.2	40.6	31.2	43.7
Early debt retirement costs	(155.1)	—	(252.4)	—
Minority interest in income of consolidated subsidiaries	(5.2)	(5.6)	(16.0)	(15.1)
Other income - net	4.9	3.7	19.7	39.7
Income from continuing operations before income taxes and cumulative effect of change in accounting principles	64.5	43.0	39.0	227.1
Provision for income taxes	48.4	23.0	42.4	136.5
Income (loss) from continuing operations	16.1	20.0	(3.4)	90.6
Income from discontinued operations	82.5	86.3	93.7	232.2
Income before cumulative effect of change in accounting principles	98.6	106.3	90.3	322.8
Cumulative effect of change in accounting principles	—	—	—	(761.3)
Net income (loss)	98.6	106.3	90.3	(438.5)
Preferred stock dividends	—	—	—	29.5
Income (loss) applicable to common stock	$ 98.6	$ 106.3	$ 90.3	$ (468.0)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ .03	$ .04	$ (.01)	$ .12
Income from discontinued operations	.16	.17	.18	.45
Income before cumulative effect of change in accounting principles	.19	.21	.17	.57
Cumulative effect of change in accounting principles	—	—	—	(1.47)
Net income (loss)	$ .19	$ .21	$ .17	$ (.90)
Weighted-average shares (thousands)	523,111	518,292	521,438	518,014
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ .03	$ .04	$ (.01)	$ .12
Income from discontinued operations	.16	.16	.18	.44
Income before cumulative effect of change in accounting principles	.19	.20	.17	.56
Cumulative effect of change in accounting principles	—	—	—	(1.45)
Net income (loss)	$ .19	$ .20	$ .17	$ (.89)
Weighted-average shares (thousands)	529,525	524,711	521,438	523,938
Cash dividends per common share	$ .01	$ .01	$ .03	$ .03

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

See accompanying notes.

The Williams Companies, Inc.

Consolidated Balance Sheet
(Unaudited)

(Dollars in millions, except per-share amounts)	September 30, 2004	December 31, 2003*
ASSETS		
Current assets:		
Cash and cash equivalents	$ 976.7	$ 2,315.7
Restricted cash	57.2	47.1
Restricted investments	—	93.2
Accounts and notes receivable less allowance of $100.7 ($112.2 in 2003)	1,266.6	1,613.2
Inventories	261.7	242.9
Derivative assets	4,100.0	3,166.8
Margin deposits	198.7	553.9
Assets of discontinued operations	68.3	441.3
Deferred income taxes	78.9	106.6
Other current assets and deferred charges	112.3	214.3
Total current assets	7,120.4	8,795.0
Restricted cash	35.5	159.8
Restricted investments	—	288.1
Investments	1,342.4	1,463.6
Property, plant and equipment, at cost	16,253.0	15,752.3
Less accumulated depreciation and depletion	(4,436.1)	(4,018.3)
	11,816.9	11,734.0
Derivative assets	3,608.2	2,495.6
Goodwill	1,014.5	1,014.5
Assets of discontinued operations	—	345.1
Other assets and deferred charges	621.2	726.1
Total assets	$25,559.1	$27,021.8
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Notes payable	$ —	$ 3.3
Accounts payable	920.7	1,228.0
Accrued liabilities	957.4	944.4
Liabilities of discontinued operations	3.8	95.7
Derivative liabilities	4,148.3	3,064.2
Long-term debt due within one year	276.6	935.2
Total current liabilities	6,306.8	6,270.8
Long-term debt	8,667.1	11,039.8
Deferred income taxes	2,302.6	2,453.4
Derivative liabilities	3,315.6	2,124.1
Other liabilities and deferred income	864.1	947.5
Contingent liabilities and commitments (Note 13)		
Minority interests in consolidated subsidiaries	94.2	84.1
Stockholders' equity:		
Common stock, $1 per share par value, 960 million shares authorized, 526.3 million issued in 2004, 521.4 million issued in 2003	526.3	521.4
Capital in excess of par value	5,221.5	5,195.1
Accumulated deficit	(1,352.1)	(1,426.8)
Accumulated other comprehensive loss	(326.3)	(121.0)
Other	(22.1)	(28.0)
	4,047.3	4,140.7
Less treasury stock (at cost), 3.2 million shares of common stock in 2004 and 2003	(38.6)	(38.6)
Total stockholders' equity	4,008.7	4,102.1
Total liabilities and stockholders' equity	$25,559.1	$27,021.8

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

See accompanying notes.

The Williams Companies, Inc.

Consolidated Statement of Cash Flows
(Unaudited)

	Nine months ended September 30,	
	2004	2003*
	(Millions)	
OPERATING ACTIVITIES:		
Income (loss) from continuing operations	$ (3.4)	$ 90.6
Adjustments to reconcile to cash provided (used) by operations:		
Depreciation, depletion and amortization	495.4	494.1
Provision for deferred income taxes	29.9	126.3
Provision for loss on investments, property and other assets	55.5	133.5
Net gain on disposition of assets	(4.5)	(125.5)
Early debt retirement costs	252.4	—
Provision for uncollectible accounts	(7.6)	6.6
Minority interest in income of consolidated subsidiaries	16.0	15.1
Amortization of stock-based awards	8.9	24.3
Payment of deferred set-up fee and fixed rate interest on RMT note payable	—	(265.0)
Accrual for fixed rate interest included in the RMT note payable	—	99.3
Amortization of deferred set-up fee and fixed rate interest on RMT note payable	—	154.5
Cash provided (used) by changes in current assets and liabilities:		
Restricted cash	(14.0)	1.0
Accounts and notes receivable	341.0	691.8
Inventories	(18.8)	54.7
Margin deposits	355.2	376.9
Other current assets and deferred charges	100.4	(18.2)
Accounts payable	(232.5)	(520.9)
Accrued liabilities	(249.7)	(450.6)
Changes in current and noncurrent derivative assets and liabilities	(128.4)	(306.3)
Changes in noncurrent restricted cash	86.5	(2.4)
Other, including changes in noncurrent assets and liabilities	(16.7)	(12.6)
Net cash provided by operating activities of continuing operations	1,065.6	567.2
Net cash provided by operating activities of discontinued operations	22.6	127.6
Net cash provided by operating activities	1,088.2	694.8
FINANCING ACTIVITIES:		
Payments of notes payable	(3.3)	(896.0)
Proceeds from long-term debt	—	1,776.5
Payments of long-term debt	(3,032.8)	(1,032.0)
Proceeds from issuance of common stock	14.7	.4
Dividends paid	(15.6)	(48.1)
Repurchase of preferred stock	—	(275.0)
Payments of debt issuance costs	(25.7)	(56.8)
Premiums paid on early debt retirement	(214.0)	—
Payments/dividends to minority interests	(5.9)	(1.1)
Changes in restricted cash	41.6	75.5
Changes in cash overdrafts	(27.4)	(46.7)
Other - net	(5.5)	.1
Net cash used by financing activities of continuing operations	(3,273.9)	(503.2)
Net cash used by financing activities of discontinued operations	(1.2)	(94.2)
Net cash used by financing activities	(3,275.1)	(597.4)
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(538.5)	(734.2)
Proceeds from dispositions	7.7	522.7
Purchases of investments/advances to affiliates	(1.6)	(20.6)
Purchases of restricted investments	(471.8)	(597.9)
Proceeds from sales of businesses	850.1	2,204.5
Proceeds from sale of restricted investments	851.4	150.0
Proceeds from dispositions of investments and other assets	86.3	81.4
Payments received on notes receivable from WilTel	68.6	15.9
Other - net	(6.0)	(.6)
Net cash provided by investing activities of continuing operations	846.2	1,621.2
Net cash used by investing activities of discontinued operations	(.8)	(23.7)
Net cash provided by investing activities	845.4	1,597.5
Increase (decrease) in cash and cash equivalents	(1,341.5)	1,694.9
Cash and cash equivalents at beginning of period**	2,318.2	1,736.0
Cash and cash equivalents at end of period**	$ 976.7	$ 3,430.9

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

** Includes cash and cash equivalents of discontinued operations of $2.5 million, $2.9 million and $85.6 million at December 31, 2003, September 30, 2003 and December 31, 2002, respectively.

See accompanying notes

The Williams Companies, Inc.

Notes to Consolidated Financial Statements
(Unaudited)

1. General

Company overview and outlook

In February 2003, we outlined our planned business strategy in response to the events that significantly impacted the energy sector and our company during late 2001 and much of 2002, including the collapse of Enron and the severe decline of the telecommunications industry. The plan focused on migrating to an integrated natural gas business comprised of a strong, but smaller, portfolio of natural gas businesses; reducing debt; and increasing our liquidity through asset sales, strategic levels of financing and reductions in operating costs. The plan was designed to address near-term and medium-term debt and liquidity issues, to de-leverage the company with the objective of returning to investment grade status and to develop a balance sheet and cash flows capable of supporting and ultimately growing our remaining businesses.

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, we successfully executed certain critical components of our plan during 2003. Key execution steps for 2004 and beyond included the completion of planned asset sales; additional reductions of our selling, general and administrative (SG&A) costs; the replacement of our cash-collateralized letter of credit and revolver facility with facilities that do not encumber cash; and continuation of efforts to exit from the Power business (see below).

Asset sales during 2004 were expected to generate proceeds of approximately $800 million. In first-quarter 2004, we completed the sale of our Alaska refinery and related assets for approximately $304 million. We completed the sale of three straddle plants in western Canada on July 28, 2004, for net proceeds of approximately $544 million (see Note 6).

On March 15, 2004, we retired $679 million of senior unsecured 9.25 percent notes. The amount represented the outstanding balance remaining after the fourth-quarter 2003 tender which retired $721 million of the original $1.4 billion balance.

In April 2004, we entered into two new unsecured credit facilities totaling $500 million, which will be used primarily for issuing letters of credit. During April 2004, use of these facilities released approximately $500 million of restricted cash, restricted investments and margin deposits. Also, on May 3, 2004, we entered into a new three-year $1 billion secured revolving credit facility. In August, we expanded the credit facility by an additional $275 million. The revolving credit facility is secured by certain Midstream assets and a guarantee from Williams Gas Pipeline Company, LLC. (WGP).

In May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of a specified series of our outstanding notes and debentures. We accepted $1.17 billion of the notes for purchase. In May 2004, we also repurchased debt of approximately $255 million of various maturities on the open market.

In August 2004, we made cash tender offers and consent solicitations for $800 million all of our 8.625 percent senior notes due 2010. We accepted $793 million of the notes for purchase.

See Note 12 for additional discussion of debt and banking arrangements.

Power business status

In mid-2002, we initiated a strategy of exiting the Power business and have worked with financial advisors to assist with this effort. However, the number of financially viable parties expressing an interest in purchasing the entire business was limited. Additionally, the current and near term view of the wholesale power market, which we interpret as depressed, has strongly influenced these parties' view of value and related risk associated with this business.

In September 2004, our Board of Directors approved the decision to retain Power and end our efforts to exit that business. Several factors affected our decision including:

- the cash flow expected to be generated by the business (Power has contracts in place expected to generate cash in amounts that substantially cover its obligations through 2010);
- the negative effect of depressed wholesale power markets on the marketability of the Power segment; and
- our progress over the last two years in reducing the risk of and increasing the certainty of cash flow from long-term power contracts.

We will continue our current program of managing this business to minimize financial risk and maximize cash flow associated with our long-term contracts.

Other

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, as restated and amended. The accompanying unaudited financial statements include all normal recurring adjustments and others, including asset impairments, loss accruals, and the change in accounting principles which, in the opinion of our management, are necessary to present fairly our financial position at September 30, 2004 and 2003, and results of operations for the three and nine months ended September 30, 2004 and 2003 and cash flows for the nine months ended September 30, 2004 and 2003.

During the second quarter of 2003, we corrected the accounting treatment previously applied to certain third-party derivative contracts during 2002 and 2001. We previously disclosed this in our Form 10-Q for the second quarter of 2003 and in our Form 10-K for the year ended December 31, 2003. Results through September 30, 2003, include $107.8 million of revenue attributable to prior periods. Our management, after consultation with our independent auditor, concluded that the effect of the previous accounting treatment was not material to 2003 and earlier periods and the trend of earnings.

During the third quarter of 2004, we corrected the accounting method previously applied to revenues from our Devils Tower production handling facility in the second quarter of 2004. The change to a units of production method resulted in a reduction of revenues of approximately $16.5 million in the third quarter related to revenues recorded in the second quarter. Our management, after consultation with our independent auditor, concluded that the effect of the previous accounting treatment was not material to the results of the second or third quarters.

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 6):

- retail travel centers concentrated in the Midsouth, part of the previously reported Petroleum Services segment;
- refining and marketing operations in the Midsouth, including the Midsouth refinery, part of the previously reported Petroleum Services segment;
- Texas Gas Transmission Corporation, previously one of Gas Pipeline’s segments;
- natural gas properties in the Hugoton and Raton basins, previously part of the Exploration & Production segment;

- bio-energy operations, part of the previously reported Petroleum Services segment;
- our general partnership interest and limited partner investment in Williams Energy Partners, previously the Williams Energy Partners segment;
- the Colorado soda ash mining operations, part of the previously reported International segment;
- certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta, previously part of the Midstream segment;
- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment;
- Gulf Liquids New River Project LLC, previously part of the Midstream segment; and
- the straddle plants in western Canada, previously part of the Midstream segment.

Management and decision-making control of certain activities have been transferred between segments. Consequently, the results of operations have been similarly reclassified. All periods presented reflect these classifications.

Unless indicated otherwise, the information in the Notes to the Consolidated Financial Statements relates to our continuing operations. Other components of our business may be classified as discontinued operations in the future as those operations are sold or classified as held-for-sale.

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. Certain other statement of operations, balance sheet and cash flow amounts have been reclassified to conform to the current classifications.

3. Cumulative effect of change in accounting principles

Energy commodity risk management and trading activities and revenues

Effective January 1, 2003, we adopted EITF 02-3. As a result of initial application of this Issue, we reduced net income by $762.5 million (net of a $471.4 million benefit for income taxes) in first-quarter 2003. Approximately $755 million of the reduction in net income relates to Power, with the remainder relating to Midstream. The reduction of net income is reported as a cumulative effect of a change in accounting principle. The change resulted primarily from power tolling, load serving, transportation and storage contracts not meeting the definition of a derivative and no longer being reported at fair value.

Asset retirement obligations

Effective January 1, 2003, we also adopted SFAS No. 143, “Accounting for Asset Retirement Obligations.” As required by the standard, we recorded liabilities equal to the present value of expected future asset retirement obligations at January 1, 2003. As a result of the adoption of SFAS No. 143, we recorded a credit to earnings of $1.2 million (net of a $.1 million provision for income taxes) reflected as a cumulative effect of a change in accounting principle. In connection with adoption of SFAS No. 143, we changed our method of accounting to include salvage value of equipment related to producing wells in the calculation of depreciation. The impact of this change is included in the effect of adoption.

Notes (Continued)

4. Asset sales, impairments and other accruals

Significant gains or losses from asset sales, impairments and other accruals included in other (income) expense — net within segment costs and expenses and investing income are included in the following tables.

	Three months ended September 30,		Nine months ended September 30,	
	2004	2003	2004	2003
	(Millions)		(Millions)	
Other (income) expense-net:				
Power				
Gain on sale of Jackson power contract	$ —	$ (13.0)	$ —	$ (188.0)
Commodity Futures Trading Commission settlement (see Note 13)	—	—	—	20.0
Gas Pipeline				
Write-off of software development costs due to cancelled implementation	—	—	—	25.5
Write-off of previously-capitalized costs	—	—	9.0	—
Exploration & Production				
Net gain on sale of certain natural gas properties	—	(2.3)	—	(96.4)
Loss provision related to an ownership dispute	—	—	11.3	—
Other				
Gain on sale of blending assets	—	(9.2)	—	(9.2)
	Three months ended September 30,		**Nine months ended September 30,**	
	2004	**2003**	**2004**	**2003**
	(Millions)		(Millions)	
Investing income:				
Power				
Gain on sale of marketable equity securities	$ —	$ 13.5	$ —	$ 13.5
Impairment of equity interest in Aux Sable	—	(5.6)	—	(14.1)
Midstream Gas & Liquids				
Gain on sale of equity interest in West Texas LPG Pipeline, L.P.	—	11.0	—	11.0
Other				
Impairment of cost-based investments	(15.7)	—	(15.7)	(13.5)
Longhorn Partners Pipeline, L.P.				
Impairment of investment	—	—	(10.8)	(42.4)
Net unreimbursed Longhorn recapitalization advisory fees	—	—	(6.5)	—
Impairment of investment in Algar Telecom S.A.	—	(1.2)	(1.1)	(13.2)

5. Provision (benefit) for income taxes

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

	Three months ended September 30,		Nine months ended September 30,	
	2004	2003	2004	2003
	(Millions)		(Millions)	
Current:				
Federal	$ (3.3)	$ 1.3	$ —	$ 13.8
State	1.2	(23.6)	5.6	(10.4)
Foreign	1.1	(1.4)	6.9	6.8
	(1.0)	(23.7)	12.5	10.2
Deferred:				
Federal	24.3	16.4	10.7	103.0
State	23.1	25.8	12.6	20.7
Foreign	2.0	4.5	6.6	2.6
	49.4	46.7	29.9	126.3
Total provision for income taxes	$ 48.4	$ 23.0	$ 42.4	$ 136.5

Notes (Continued)

The effective income tax rate for the three and nine months ended September 30, 2004, is significantly greater than the federal statutory rate due primarily to the effect of state income taxes (including no state income tax benefit recognized for state net operating losses) and net foreign operations.

The effective income tax rate for the three months ended September 30, 2003, is greater than the federal statutory rate due primarily to the effect of state income taxes, net foreign operations and an accrual for income tax contingencies. For the nine months ended September 30, 2003, the effective income tax rate is greater than the federal statutory rate due primarily to the effect of state income taxes, net foreign operations, an accrual for income tax contingencies, nondeductible expenses, the financial impairment of certain investments and capital losses generated for which valuation allowances were established.

On October 22, 2004, the American Jobs Creation Act of 2004 (the Act) was signed into law. The Act repeals the foreign sales corporation/extraterritorial income exclusion provision of the Internal Revenue Code, provides a deduction with respect to income of certain U.S. manufacturing activities, allows for tax-favored repatriation of offshore earnings, and makes numerous other changes to the U.S. tax rules. We are evaluating the potential accounting impact of this new legislation.

6. Discontinued operations

During 2002, we began the process of selling assets and/or businesses to address liquidity issues. The businesses discussed below represent components that have been sold or approved for sale by our Board of Directors as of September 30, 2004; 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.

Summarized results of discontinued operations

The following table presents the summarized results of discontinued operations for the three and nine months ended September 30, 2004 and September 30, 2003. Loss from discontinued operations before income taxes for the three and nine months ended September 30, 2004 includes charges of $134.4 million and $151.8 million, respectively, to increase our accrued liability associated with certain Quality Bank litigation matters (see Note 13). The benefit for income taxes for the three months ended September 30, 2004, includes the favorable effect of net Canadian tax benefits realized from the sale of the Canadian straddle plants.

	Three months ended September 30,		Nine months ended September 30,	
	2004	2003	2004	2003
	(Millions)		(Millions)	
Revenues	$ 25.1	$484.7	$ 364.7	$2,331.0
Income (loss) from discontinued operations before income taxes	$(126.7)	$ 16.7	$(118.5)	$ 136.1
(Impairments) and gain (loss) on sales - net	192.9	72.3	199.9	187.9
Benefit (provision) for income taxes	16.3	(2.7)	12.3	(91.8)
Income from discontinued operations	$ 82.5	$ 86.3	$ 93.7	$ 232.2

Summarized assets and liabilities of discontinued operations

The following table presents the summarized assets and liabilities of discontinued operations as of September 30, 2004 and December 31, 2003. The December 31, 2003 balances include the assets and liabilities of the Canadian straddle plants, the Gulf Liquids New River Project LLC (Gulf Liquids) and the Alaska refining, retail and pipeline operations. The September 30, 2004 balances include Gulf Liquids and certain Alaska retail operations that were not included in the March 31, 2004 sale but that remain held for sale. The assets and liabilities from discontinued operations are reflected on the Consolidated Balance Sheet as current beginning in the period they are both approved for sale and expected to be sold within twelve months.

	September 30, 2004	December 31, 2003
	(Millions)	
Total current assets	$ 8.4	$175.4
Property, plant and equipment - net	58.9	609.0
Other non-current assets	1.0	2.0
Total non-current assets	59.9	611.0
Total assets	$68.3	$786.4
Long-term debt due within one year	$ —	$ 1.2
Other current liabilities	2.9	81.5
Total current liabilities	2.9	82.7
Long-term debt	—	.3
Other non-current liabilities	.9	12.7
Total non-current liabilities	.9	13.0
Total liabilities	$ 3.8	$ 95.7

Notes (Continued)

Held for sale at September 30, 2004

Gulf Liquids New River Project LLC

During second-quarter 2003, our Board of Directors approved a plan authorizing management to negotiate and facilitate a sale of the assets of Gulf Liquids. The Gulf Liquids assets were written down to their estimated fair value less cost to sell resulting in a second-quarter 2003 impairment charge of $92.6 million, which is included in (Impairments) and gain (loss) on sales - net in the preceding table of summarized results of discontinued operations. We estimated fair value based on a probability-weighted analysis of various scenarios, including expected sales prices, discounted cash flows and salvage valuations. During first-quarter 2004, we initiated a second bid process and expect the sale of these operations to be completed in the fourth-quarter of 2004. These operations were part of the Midstream segment.

Winterthur International Insurance Company (Winterthur) issued policies to Gulf Liquids providing financial assurance related to construction contracts among Gulf Liquids, Gulsby Engineering, Inc. and Gulsby-Bay. After disputes arose regarding obligations under the construction contracts, Winterthur disputed coverage resulting in arbitration between Winterthur and Gulf Liquids. In July 2004, the arbitration panel awarded Gulf Liquids $93.6 million, offset by $18 million previously paid to Gulf Liquids, plus interest of $9.4 million, for a total award to Gulf Liquids of approximately $85 million including interest through November 1, 2004. Following the arbitration decision, Winterthur filed a Petition to Vacate the Final Award in the New York State court and Gulf Liquids filed a Cross-Petition to Confirm the Final Award. Prior to the State court's ruling, Winterthur agreed to the terms of the award and on November 1, 2004 remitted approximately $85 million to us. As a result, we will recognize pre-tax income of $95 to $100 million within Income from discontinued operations in the fourth quarter.

2004 completed transactions

Canadian straddle plants

On July 28, 2004, we completed the sale of the Canadian straddle plants for approximately $544 million in U.S. funds, including amounts paid to our subsidiaries for amounts previously due from the straddle plants. During third-quarter 2004, we recognized a pre-tax gain on the sale of $189.8 million, which is included in (Impairments) and gain (loss) on sales — net in the preceding table of summarized results of discontinued operations. These assets were previously written down to estimated fair value, resulting in a $36.8 million impairment in fourth-quarter 2002 and an additional $41.7 million impairment in fourth-quarter 2003. In 2004, the fair value of the assets increased substantially due primarily to renegotiation of certain customer contracts and a general improvement in the market for processing assets. These 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 and related assets for approximately $304 million, subject to closing adjustments for items such as the value of petroleum inventories. We received $279 million in cash at the time of sale and $25 million in cash during the second quarter of 2004. Throughout the sales negotiation process, we regularly reassessed the estimated fair value of these assets based on information obtained from the sales negotiations using a probability-weighted approach. We recognized a $3.6 million gain on the sale during first-quarter 2004. The gain and an $8 million first-quarter 2003 impairment charge are included in (Impairments) and gain (loss) on sales — net in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

2003 Completed transactions

Canadian liquids operations

During the third quarter of 2003, we completed the sale of certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at our Redwater, Alberta plant for total proceeds of $246 million in cash. We recognized pre-tax gains totaling $86.6 million on the sales which are included in (Impairments) and gain (loss) on sales — net in the preceding table of summarized results of discontinued operations. These operations were part of the Midstream segment.

Notes (Continued)

Soda ash operations

On September 9, 2003, we completed the sale of our soda ash mining facility located in Colorado. These assets were written down to their estimated fair value less cost to sell in 2002. During 2003, ongoing sale negotiations continued to provide new information regarding estimated fair value, and, as a result, additional impairment charges of $17.4 million were recognized in 2003. We also recognized a loss on the sale of $4.2 million. The 2003 impairments and the loss on sale are included in (Impairments) and gain (loss) on sales - net in the preceding table of summarized results of discontinued operations. The soda ash operations were part of the previously reported International segment.

Williams Energy Partners

On June 17, 2003, we completed the sale of our 100 percent general partnership interest and 54.6 percent limited partner investment in Williams Energy Partners for approximately $512 million in cash and assumption by the purchasers of $570 million in debt. In December 2003, we received additional cash proceeds of $20 million following the occurrence of a contingent event. In second-quarter 2003 we recognized a gain on sale — net of $275.6 million which is included in (Impairments) and gain (loss) on sales — net in the preceding table of summarized results of discontinued operations and deferred an additional $113 million associated with certain environmental indemnifications we provided to the purchasers under the sales agreement. In second-quarter 2004, we settled these indemnifications with an agreement to pay $117.5 million over a four-year period (see Note 11).

Bio-energy facilities

On May 30, 2003, we completed the sale of our bio-energy operations for approximately $59 million in cash. During second-quarter 2003, we recognized a loss on sale of $6.4 million, which is included in (Impairments) and gain (loss) on sales — net in the preceding table of summarized results of discontinued operations. These assets were previously written down to their estimated fair value less cost to sell at December 31, 2002. These operations were part of the previously reported Petroleum Services segment.

Natural gas properties

On May 30, 2003, we completed the sale of natural gas exploration and production properties in the Raton Basin in southern Colorado and the Hugoton Embayment in southwestern Kansas. This sale included all of our interests within these basins. During second-quarter 2003, we recognized a gain on sale of $39.9 million which is included in (Impairments) and gain (loss) on sales - net in the preceding table of summarized results of discontinued operations. These properties were part of the Exploration & Production segment.

Texas Gas

On May 16, 2003, we completed the sale of Texas Gas Transmission Corporation for $795 million in cash and the assumption by the purchaser of $250 million in existing Texas Gas debt. There was no significant gain or loss recognized on the sale. We recorded a $109 million impairment charge in first-quarter 2003 reflecting the excess of the carrying cost of the long-lived assets over our estimate of fair value based on our assessment of the expected sales price pursuant to the purchase and sale agreement. The impairment charge is included in (Impairments) and gain (loss) on sales — net in the preceding table of summarized results of discontinued operations. Texas Gas was a segment within Gas Pipeline.

Midsouth refinery and related assets

On March 4, 2003, we completed the sale of our refinery and other related operations located in Memphis, Tennessee for $455 million in cash. These assets were previously written down to their estimated fair value less cost to sell at December 31, 2002. We recognized a pre-tax gain on sale of $4.7 million in the first quarter of 2003. During the second quarter of 2003, we recognized a $24.7 million gain on the sale of an earn-out agreement we retained in the sale of the refinery. These gains are included in (Impairments) and gain (loss) on sales — net in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

Notes (Continued)

Williams travel centers

On February 27, 2003, we completed the sale of our travel centers for approximately $189 million in cash. We had previously written these assets down to their estimated fair value to sell at December 31, 2002, and did not recognize a significant gain or loss on the sale. These operations were part of the previously reported Petroleum Services segment.

7. Earnings (loss) per share

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

	Three months ended September 30,		Nine months ended September 30,	
	2004	2003	2004	2003
	(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	$ 16.1	$ 20.0	$ (3.4)	$ 90.6
Convertible preferred stock dividends	—	—	—	(29.5)
Income (loss) from continuing operations available to common stockholders for basic and diluted earnings per share	$ 16.1	$ 20.0	$ (3.4)	$ 61.1
Basic weighted-average shares	523,111	518,292	521,438	518,014
Effect of dilutive securities:				
Stock options	3,716	4,155	—	3,261
Deferred shares unvested	2,698	2,264	—	2,663
Convertible debentures	—	—	—	—
Diluted weighted-average shares	529,525	524,711	521,438	523,938
Earnings (loss) per share from continuing operations:				
Basic	$ .03	$ .04	$ (.01)	$ .12
Diluted	$ .03	$ .04	$ (.01)	$ .12

For the nine months ended September 30, 2004, approximately 3.7 million weighted-average stock options and approximately 2.7 million weighted-average unvested deferred shares that otherwise would have been included, have been excluded from the computation of diluted earnings per common share (EPS) as their inclusion would be antidilutive due to our loss from continuing operations. The unvested deferred shares will vest over the period from November 2004 to January 2008.

In addition, for the three and nine months ended September 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 EPS as their inclusion would be antidilutive. If no other components used to calculate diluted EPS change, we estimate the assumed conversion of the convertible debentures would become dilutive and, therefore, be included in diluted EPS at an Income from continuing operations amount of $49 million and $144.7 million for the three and nine months ended September 30, 2004, respectively.

Approximately 9.3 million options to purchase shares of common stock with a weighted-average exercise price of $27.44 and an exercise price range of $12.22 — $42.29 were outstanding at September 30, 2004, but have been excluded from the computation of diluted EPS. Inclusion of these shares would have been antidilutive, as the exercise prices of the options exceeded the third-quarter weighted average market price of the common shares of $11.97 for the three months ended September 30, 2004.

For the nine months ended September 30, 2003, approximately 8.6 million weighted-average shares related to the assumed conversion of 9.875 percent cumulative convertible preferred stock have been excluded from the computation of diluted EPS as their inclusion would be antidilutive. The preferred stock was redeemed in June 2003.

For the three and nine months ended September 30, 2003, approximately 27.5 million and 12.7 million weighted-average shares, respectively, related to the assumed conversion of convertible debentures, as well as the related interest, were excluded from the computation of diluted EPS as their inclusion would be antidilutive. If no other components used to calculate diluted EPS change, we estimate the assumed conversion of the convertible debentures would become dilutive and, therefore, be included in diluted EPS at an Income from continuing operations applicable to common stock amount of $48.5 million and 143.5 million for the three and nine months ended September 30, 2003, respectively.

Notes (Continued)

On September 17, 2004, we initiated an offer to exchange up to 43.9 million FELINE PACS units for one share of our common stock plus $1.47 in cash for each unit (see Note 12). On October 22, 2004, we issued approximately 33.1 million shares of our common stock related to this exchange offer. The increase in shares will have a dilutive effect on EPS in the future.

8. Employee benefit plans

Net periodic pension and other postretirement benefit (income) expense for the three and nine months ended September 30, 2004 and 2003 is as follows:

	Pension Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2004	2003	2004	2003
	(Millions)		(Millions)	
Components of net periodic pension expense:				
Service cost	$ 6.0	$ 6.5	$ 18.1	$ 19.4
Interest cost	12.7	13.3	37.9	39.9
Expected return on plan assets	(16.3)	(13.7)	(48.7)	(41.1)
Amortization of prior service credit	(.3)	(.7)	(1.1)	(1.9)
Recognized net actuarial loss	2.4	3.5	7.0	10.3
Regulatory asset amortization	.5	.9	1.5	1.1
Settlement/curtailment expense	—	—	.1	.6
Net periodic pension expense	$ 5.0	$ 9.8	$ 14.8	$ 28.3

	Other Postretirement Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2004	2003	2004	2003
	(Millions)		(Millions)	
Components of net periodic postretirement benefit (income) expense:				
Service cost	$ .6	$ 1.5	$ 2.4	$ 4.7
Interest cost	3.3	5.7	14.1	18.4
Expected return on plan assets	(3.1)	(3.1)	(9.3)	(9.9)
Amortization of transition obligation	.7	.7	2.0	2.1
Amortization of prior service cost	.2	.2	.5	.5
Regulatory asset amortization	1.5	1.3	5.0	6.0
Settlement/curtailment (income) expense	—	—	—	(29.0)
Net periodic postretirement benefit (income) expense	$ 3.2	$ 6.3	$ 14.7	$ (7.2)

The $29 million settlement/curtailment income included in net periodic postretirement benefit (income) expense for the nine months ended September 30, 2003, is included in income (loss) from discontinued operations in the Consolidated Statement of Operations due to the settlement/curtailment directly resulting from the sale of the operations included within discontinued operations.

As previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2003, as restated and amended, we expected to contribute approximately $60 million to our pension plans and approximately $15 million to our other postretirement benefit plans in 2004. For the nine months ended September 30, 2004, we contributed $44.5 million to our pension plans and $9.7 million to our other postretirement benefit plans. We presently anticipate contributing approximately an additional $16 million to fund our pension plans in 2004 for a total of approximately $61 million. We presently anticipate contributing approximately an additional $4 million to our other postretirement benefit plans in 2004 for a total of approximately $14 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) 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. In accordance with FASB Staff Position (FSP) No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," the provisions of the Act were not reflected in any measures of benefit obligations or other postretirement benefit expense in the financial statements or accompanying notes until further guidance was effective. In May 2004, the FASB issued FSP No. FAS 106-2, "Accounting and

Notes (Continued)

Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." Although final guidance has not been issued, we believe the prescription drug benefits included in our health care plans for retirees, as of September 30, 2004, are actuarially equivalent to Medicare Part D. In accordance with FSP No. FAS 106-2, we have reflected the effect of the subsidy on the measurement of net periodic postretirement benefit (income) expense beginning July 1, 2004. Net periodic postretirement benefit (income) expense for the three and nine months ended September 30, 2004, reflects a reduction of $2.6 million, including a decrease in service cost of $.3 million and decrease in interest cost of $2.0 million. The reduction in the benefit obligation is approximately $43 million as of January 1, 2004. Although we believe our plans, as of September 30, 2004, are actuarially equivalent to Medicare Part D, we expect to amend our plans 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. If this amendment had been effective January 1, 2004, we would have expected this amendment to have further decreased the benefit obligation by approximately $60 million.

9. Stock-based compensation

Employee stock-based awards are accounted for under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25) and related interpretations. Fixed-plan common stock options generally do not result in compensation expense because the exercise price of the stock options 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 if we had applied the fair value recognition provisions of SFAS No. 123 "Accounting for Stock-Based Compensation."

	Three months ended September 30,		Nine months ended September 30,	
	2004	2003	2004	2003
	(Millions)		(Millions)	
Net income (loss), as reported	$ 98.6	$ 106.3	$ 90.3	$ (438.5)
Add: Stock-based employee compensation included in the Consolidated Statement of Operations, net of related tax effects	2.3	3.1	8.1	17.0
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(9.7)	(6.7)	(20.3)	(27.7)
Pro forma net income (loss)	$ 91.2	$ 102.7	$ 78.1	$ (449.2)
Earnings (loss) per share:				
Basic-as reported	$ .19	$ .21	$ .17	$ (.90)
Basic-pro forma	$ .17	$ .20	$ .15	$ (.92)
Diluted-as reported	$ .19	$ .20	$ .17	$ (.89)
Diluted-pro forma	$ .17	$ .20	$ .15	$ (.91)

Pro forma amounts for 2004 include compensation expense from awards of our company stock made in 2004, 2003, 2002 and 2001. Also included in pro forma expense for the three and nine months ended September 30, 2004, is $886,000 and $2.6 million, respectively, of incremental expense associated with the stock option exchange program described below. Pro forma amounts for 2003 include compensation expense from awards made in 2003, 2002 and 2001.

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.

On May 15, 2003, our shareholders approved a stock option exchange program. Under this exchange program, eligible employees were given a one-time opportunity to exchange certain outstanding options for a proportionately lesser number of options at an exercise price to be determined at the grant date of the new options. Surrendered options were cancelled June 26, 2003, and replacement options were granted on December 29, 2003. We did not recognize any expense pursuant to the stock option exchange. However, for purposes of pro forma disclosures, we recognized additional expense related to these new options and will amortize the remaining expense on the cancelled options through year-end 2004.

Notes (Continued)

10. Inventories

Inventories at September 30, 2004 and December 31, 2003 are as follows:

	September 30, 2004	December 31, 2003
	(Millions)	
Finished goods:		
Refined products	$ .8	$ 8.0
Natural gas liquids	52.6	40.4
	53.4	48.4
Natural gas in underground storage	145.3	132.5
Materials, supplies and other	63.0	62.0
	$261.7	$242.9

11. Accrued liabilities and other liabilities and deferred income

On May 26, 2004, we were released from certain historical indemnities, primarily related to environmental remediation, for an agreement to pay $117.5 million (see Note 13). We had previously deferred $113 million of a gain on sale related to these indemnities. At the date of sale, the deferred revenue and identified obligations related to the indemnities totaled $102 million. At September 30, 2004, the net book value of this settlement is $73.7 million. We will pay the balance in three installments of $27.5 million, $20 million, and $35 million on July 1, 2005, 2006, and 2007, respectively.

During the third quarter of 2004, we recorded an additional accrual in Accrued liabilities of approximately $134 million related to certain Quality Bank litigation matters (see Note 13).

Notes (Continued)

12. Debt and banking arrangements

Notes payable and long-term debt

Notes payable and long-term debt at September 30, 2004 and December 31, 2003, are as follows:

	Weighted-Average Interest Rate (1)	September 30, 2004	December 31, 2003
		(Millions)	
Secured notes payable	—%	$ —	$ 3.3
Long-term debt:			
Secured long-term debt			
Notes, 6.62%-9.45%, payable through 2016	8.0%	$ 222.7	$ 243.7
Notes, adjustable rate, payable through 2016	4.1%	588.6	602.5
Unsecured long-term debt			
Debentures, 5.5%-10.25%, payable through 2033	7.1%	1,408.2	1,645.2
Notes, 6.125%-9.25%, payable through 2032 (2)	7.5%	6,723.9	9,404.3
Other, payable through 2007	6.0%	.3	79.3
Total long-term debt		8,943.7	11,975.0
Long-term debt due within one year		(276.6)	(935.2)
Long-term debt		$8,667.1	$11,039.8

(1) At September 30, 2004.

(2) Includes $1.1 billion of 6.5 percent notes payable 2007, subject to remarketing in November 2004, discussed below.

Long-term debt includes $1.1 billion of 6.5 percent notes, payable in 2007, which are subject to remarketing in November 2004. These FELINE PACS include equity forward contracts that require the holder to purchase shares of our common stock in February 2005. If a remarketing is unsuccessful in 2004 and a second remarketing in February 2005 is unsuccessful as defined in the offering document for the FELINE PACS, then we could exercise our right to foreclose on the notes in order to satisfy the obligation of the holders of the equity forward contracts requiring the holder to purchase our common stock. This would be a non-cash transaction. If either remarketing of the notes is successful, we will receive the proceeds from the remarketing in February 2005 and issue stock to the holders of the forward contracts (see *Recent events* below).

Recent events

On February 25, 2004, our Exploration & Production segment amended its $500 million secured variable rate note. The amendment reduced the floating interest rate from the London InterBank Offered Rate (LIBOR) plus 3.75 percent to LIBOR plus 2.5 percent. The amendment also extended the maturity date from May 30, 2007 to May 30, 2008. The amendment provides for an additional reduction in the interest rate by 25 basis points, or 0.25 percent, if we meet certain credit-rating requirements. The significant covenants were not altered by the amendment.

In May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of a specified series of our outstanding notes and debentures. As of the June 8, 2004, tender offer expiration date, we had accepted for purchase tenders of notes and debentures with an aggregate principal amount of approximately $1.17 billion. Holders of notes and debentures tendered by the early tender expiration date received an early tender payment premium of $30 per $1,000 principal amount of notes and debentures. In May 2004, we also repurchased approximately $255 million of various notes with maturity dates ranging from 2006 to 2011. In conjunction with these tendered notes and debentures and related consents, and early retirements, we paid premiums of approximately $79 million. The premiums, as well as related fees and expenses, together totaling approximately $97 million, have been recorded during 2004 as early debt retirement costs.

Notes (Continued)

On July 20, 2004, Wilpro Energy Services (PIGAP II) Limited, one of our subsidiaries, received a notice of default from the Venezuelan state oil company, PDVSA, relating to certain operational issues alleging that our subsidiary is not in compliance under a services agreement. We do not believe a basis exists for such notice and are contesting the giving of this notice. Although this notice of default could result in an event of default with respect to project loans totaling approximately $208 million, such an event would not adversely affect any of our other debt instruments. The lenders under the project loan agreement have confirmed to us in writing that based on the facts they currently know, they have no intention of exercising any rights or remedies under the project loan agreement until the issues raised in the notice and our response are clarified.

In August 2004, we made cash tender offers and consent solicitations for all $800 million of our 8.625 percent senior notes due 2010. As of the September 2, 2004, tender offer expiration date, we had accepted $793 million of notes for purchase. Holders of notes tendered by the early tender expiration date received an early tender payment premium of $20 per $1,000 principal amount of notes. In conjunction with these tendered notes and related consents, we paid premiums of approximately $134.5 million. The premiums, as well as related fees and expenses, together totaling approximately $154.7 million were recorded in third-quarter 2004 as early debt retirement costs.

On September 17, 2004, we initiated an offer to exchange up to 43.9 million FELINE PACS units for one share of our common stock plus $1.47 in cash for each unit. The offer expired October 18, 2004, and resulted in approximately 33.1 million of the 44 million issued and outstanding units being tendered and accepted for exchange. The exchange offer reduced our 6.5 percent notes, due 2007, by approximately $827 million and increased our common stock outstanding by 33.1 million shares. The effect of the exchange, including a pre-tax charge for related expenses of approximately $25 million, will be reflected in the fourth quarter. At September 30, 2004, the $1.1 billion obligation associated with the FELINE PACS is classified as long-term debt. Following the exchange and in connection with the remarketing of the senior notes that is scheduled to take place on November 10, 2004, we have provided notice that we may submit an order to purchase a portion of the senior notes not to exceed approximately $200 million. We propose to retire all the senior notes we purchase in the remarketing.

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.

Revolving credit and letter of credit facilities

In April 2004, we entered into two unsecured bank revolving credit facilities totaling $500 million. These facilities provide for both borrowings and issuing letters of credit, but are used primarily for issuing letters of credit. At September 30, 2004, letters of credit totaling $493 million have been issued by the participating financial institution under these facilities and no revolving credit loans were outstanding. We are required to pay to the bank fixed fees at a weighted-average rate of 3.64 percent on the total committed amount of the facilities. In addition, we pay interest on any borrowings at a fluctuating rate comprised of either a base rate or LIBOR. We were able to obtain the unsecured credit facilities because the funding bank syndicated its associated credit risk into the institutional investor market via a 144A offering, which allows for the resale of certain restricted securities to qualified institutional buyers. Upon the occurrence of certain credit events, letters of credit outstanding under the agreement become cash collateralized creating a borrowing under the facilities. Concurrently the bank can deliver the facilities to the institutional investors, whereby the investors replace the bank as lender under the facilities. Upon such occurrence, we will pay:

- a fixed facility fee at a weighted average rate of 3.19 percent to the investors,
- interest on borrowings under the $400 million facility equal to a fixed rate of 3.57 percent, and
- interest on borrowings under the $100 million facility at a fluctuating LIBOR interest rate.

Notes (Continued)

To facilitate the syndication of these facilities, the bank established trusts funded by the institutional investors. The assets of the trusts serve as collateral to reimburse the bank for our borrowings in the event the facilities are delivered to the investors. Thus, we have no asset securitization or collateral requirements under the new facilities. During second-quarter 2004, use of these new facilities replaced existing facilities and released approximately $500 million of restricted cash, restricted investments and margin deposits which secured our previous $800 million revolving and letter of credit facility. Significant covenants under these new facilities include the following:

- limitations on certain payments, including a limitation on the payment of quarterly dividends to no greater than $.05 per common share;
- limitations on asset sales;
- limitations on the use of proceeds from permitted asset sales;
- limitations on transactions with affiliates; and
- limitations on the incurrence of additional indebtedness and issuance of disqualified stock, unless the fixed charge coverage ratio for our most recently ended four full fiscal quarters is at least 2 to 1, determined on a proforma basis.

On May 3, 2004, we entered into a new three-year, $1 billion secured revolving credit facility which is available for borrowings and letters of credit. In August 2004, we expanded the credit facility by an additional $275 million. At September 30, 2004, letters of credit totaling $438 million have been issued by the participating institutions under this facility and no revolving credit loans were outstanding. Northwest Pipeline Corporation (Northwest) and Transcontinental Gas Pipe Line Corporation (Transco) have access to $400 million each under the facility. The new facility is secured by certain Midstream assets, including substantially all of our southwest Wyoming, Wamsutter, San Juan Conventional, Manzanares and Torre Alta systems. Additionally, the facility is guaranteed by WGP. Interest is calculated based on a choice of two methods: a fluctuating rate equal to the facilitating bank's base rate plus an applicable margin or a periodic fixed rate equal to LIBOR plus an applicable margin. We are also required to pay a commitment fee based on the unused portion of the facility, currently .375 percent. The applicable margins and commitment fee are based on the relevant borrower's senior unsecured long-term debt ratings. Significant financial covenants under the credit agreement include:

- ratio of debt to capitalization no greater than (i) 75 percent for the period June 30, 2004 through December 31, 2004, (ii) 70 percent for the period after December 31, 2004 through December 31, 2005, and (iii) 65 percent for the remaining term of the agreement;
- ratio of debt to capitalization no greater than 55 percent for Northwest and Transco; and
- ratio of EBITDA to Interest, on a rolling four quarter basis (or, in the first year, building up to a rolling four quarter basis), no less than (i) 1.5 for the periods ending September 30, 2004 through March 31, 2005, (ii) 2.0 for any period after March 31, 2005 through December 31, 2005, and (iii) 2.5 for the remaining term of the agreement.

Upon entering into the new $1 billion secured revolving credit facility on May 3, 2004, we terminated the $800 million revolving and letter of credit facility which we entered into in June 2003. Termination of the facility resulted in a $3.8 million charge which is recorded in Interest accrued in the Consolidated Statement of Operations.

Retirements

On March 15, 2004, we retired $679 million of senior, unsecured 9.25 percent notes. The amount represented the outstanding balance remaining after the fourth-quarter 2003 tender which retired $721 million of the original $1.4 billion balance.

As previously discussed, in May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of our specified series of outstanding notes and debentures. We accepted for purchase tenders of notes and debentures with an aggregate principal amount of approximately $1.17 billion. In May 2004, we also repurchased approximately $255 million of various notes with maturity dates ranging from 2006 to 2011.

In August 2004, we made cash tender offers and consent solicitations for all $800 million of our 8.625 percent senior notes due 2010. We accepted for purchase tenders of notes with an aggregate principal amount of approximately $793 million.

Notes (Continued)

A summary of significant payments of long-term debt for the nine months ended September 30, 2004 is as follows:

Issue/Terms	Due Date	Principal Amount
		(Millions)
8.625% senior notes	2010	$792.8
9.25% senior unsecured notes	2004	678.5
6.75% PATS	2006	370.3
6.5% unsecured notes	2006	251.4
6.25% unsecured debentures	2006	231.0
6.5% unsecured notes	2008	221.9
7.55% unsecured notes	2007	118.8
6.625% unsecured notes	2004	101.6
7.25% unsecured notes	2009	85.0
Long-term debt collateralized by certain receivables	N/A	78.7
7.125% unsecured notes	2011	60.0
Various notes and debentures, 6.62% - 9.45%	2007-2016	28.5
Various notes, adjustable rate	2008-2016	13.9

13. 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 $9 million for potential refund as of September 30, 2004.

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, California Independent System Operator (ISO) fines, 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, major California utilities, and others that have substantially resolved each of these issues. However, certain of these issues remain open at the FERC and for other non-settling parties.

Refund proceedings

Although we have entered into a global settlement with the State of California, certain California utilities, and various other parties that resolve the refund issues among the settling parties, we have potential refund exposure to non-settling parties (e.g., various California end users that have not agreed to opt into the utility settlement). As a part of the utility settlement, Williams funded escrow accounts that we anticipate will satisfy any ultimate refund determinations in favor of the non-settling parties. Williams is also owed interest from counterparties in the California market during the refund period of approximately $29 million through September 30, 2004. A request for rehearing of the order approving the utility settlement is pending at the FERC. 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. No schedule has yet been established for hearing the appeals.

Summer 2002 90-day contracts

On May 2, 2002, PacifiCorp filed a complaint with the FERC against us 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 United States Court of Appeals for the DC Circuit 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 were resolved pursuant to the utility 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 United Sates Department of Justice (DOJ) investigation regarding gas and power trading.

Notes (Continued)

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 a settlement agreement with the State of California and other non-federal parties that includes renegotiated long-term energy contracts. These contracts are made up of block energy sales, dispatchable products and a gas contract. The settlement does not extend to criminal matters or matters of willful fraud, but also resolved 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 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 settlement. On June 29, 2004, the court approved the settlement, making it effective as to plaintiffs and terminating the class actions as to us. An appeal of this order is currently pending. Some litigation by non-California plaintiffs, or relating to reporting of natural gas information to trade publications, as discussed below, will continue. As of September 30, 2004, pursuant to the terms of the settlement, we have transferred ownership of six LM6000 gas powered electric turbines, have made two payments totaling $72 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 settlement. An additional $75 million remains to be paid to the California Attorney General (or his designee) over the next six 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 completed our response to the subpoena. The DOJ's investigation into this matter is continuing. 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 where 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 in federal court in New York, Washington, Oregon and California and in state court in California.

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 investigation is continuing. The FERC inquiries relate to the sharing of non-public data concerning inventory levels and the potential uses of such data in natural gas trading.

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 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 $55 million, excluding interest, through September 30, 2004, 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.

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 September 30, 2004, Transco had accrued liabilities of $26 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances.

We also accrued environmental remediation costs for our natural gas gathering and processing facilities, primarily related to soil and groundwater contamination. At September 30, 2004, 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. The NOV specified that the maximum statutory penalty for such violations is approximately $13.7 million. NMED and WFS are negotiating a possible resolution to this matter and WFS anticipates that any proposed penalty will be significantly lower than the maximum statutory amount. Additionally, in August 2004, WFS 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. NMED and WFS are also negotiating a possible resolution to this matter.

Former operations, including operations classified as discontinued

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

Agrico

In connection with the 1987 sale of the assets of Agrico Chemical Company, we agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations to the extent such costs exceed a specified amount. At September 30, 2004, we had accrued liabilities of approximately $10 million for such excess costs.

We are also in discussions with defendants involved in two settled class action damages lawsuits involving one former chemical fertilizer site in Florida. We were not a named defendant in the lawsuits, but have contractual obligations to participate with the named defendants in the ongoing remediation. One named defendant has filed a motion to compel us to participate in arbitration over the contractual obligations for a site in Florida. A hearing was held on that motion on September 2, 2004, and we await the court's ruling.

Williams Energy Partners

As part of our June 17, 2003 sale of Williams Energy Partners (see Note 6), we indemnified the purchaser for:

(1) environmental cleanup costs resulting from certain conditions, primarily soil and groundwater contamination, at specified locations, to the extent such costs exceed a specified amount, and

(2) currently unidentified environmental contamination relating to operations prior to April 2002 and identified prior to April 2008.

On May 26, 2004, the parties reached an agreement for buyout of certain indemnities in the form of a structured cash settlement totaling $117.5 million (see Note 11). Yearly payments will be made through 2007. The agreement releases us from all environmental indemnity obligations under the June 2003 sale of Williams Energy Partners and two related agreements. We are now indemnified by the purchaser for third party environmental claims made against us for claims covered under the June 2003 purchase and sale agreement (Williams Energy Partners PSA) and related agreements as well as all environmental occurrences before the closing date of the Williams Energy Partners PSA. The agreement also transferred most third party litigation matters related to Williams Energy Partners' assets to the purchaser.

On July 2, 2001, the EPA issued an information request asking for information on oil releases and discharges in any amount from our pipelines, pipeline systems, and pipeline facilities used in the movement of oil or petroleum products, during the period from July 1, 1998 through July 2, 2001. In November 2001, we furnished our response. On March 11, 2004, the DOJ invited the new owner of Williams Energy Partners, Magellan Midstream Partners, L.P. (Magellan), to enter into negotiations regarding alleged violations of the Clean Water Act and to sign a tolling agreement. No penalty has been assessed by the EPA; however, the DOJ stated in its letter that the maximum possible penalties were approximately $22 million for the alleged violations. It is anticipated that by providing additional clarification and through negotiations with the EPA and DOJ, that any proposed penalty will be reduced. All environmental indemnity obligations to Magellan were released in the May 26, 2004 buyout agreement described above. We will participate in the EPA and DOJ negotiations and respond to requests for information related to three release events not related to Magellan-owned assets.

Other

At September 30, 2004, we had accrued environmental liabilities totaling approximately $17 million related primarily to our:

- potential indemnification obligations to purchasers of our former retail petroleum and refining operations;
- former propane marketing operations, petroleum products and natural gas pipelines;
- a discontinued petroleum refining facility; and
- exploration and production and mining operations.

These costs include (1) certain conditions at specified locations related primarily to soil and groundwater contamination and (2) any penalty assessed on Williams Refining & Marketing, LLC (Williams Refining) associated with noncompliance with EPA's benzene waste "NESHAP" regulations. 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 its new owner 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 will continue on December 7, 2004, and are expected to continue into 2005 to resolve the allegations of noncompliance. In connection with the sale of the Memphis refinery in March 2003, we agreed to indemnify the purchaser for any such penalty.

We are a plaintiff in litigation involving the environmental investigation and subsequent cleanup of our former retail petroleum and refining operations. In April 2004, we received a court order to participate in mediation before the end of June with the defendant to attempt to reach a settlement prior to going to trial. Mediation began in June and discussions are ongoing.

Certain of our subsidiaries have been identified as potentially responsible parties (PRP) 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.

Notes (Continued)

Summary of environmental matters

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

Other legal matters

Royalty indemnifications

In 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.

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 September 30, 2004, 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. The plaintiff is seeking an appeal.

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, for more than one year. 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 intend to continue their opposition to class certification.

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 sale of Kern River and Texas Gas, 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.

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 dollars. 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 moved to lift the stay and filed an amended complaint against one of our Exploration & Production subsidiaries.

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. 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 from these cases. If granted, costs incurred as a result of these indemnifications will not be covered by our insurance policies. 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. On April 2, 2004, 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. 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.

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. The U.S. Department of Labor is also independently investigating our employee benefit plans. On May 3, 2004, plaintiffs requested permission to amend their complaint to add additional investment committee members and to again name the board of directors. That permission was granted June 7, 2004, and a motion to dismiss was filed on behalf of the board on July 15, 2004.

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.

Shell offshore litigation

On November 30, 2001, Shell Offshore, Inc. filed a complaint at the FERC against four of our subsidiaries, including Williams Field Services Company (WFS) and Transco, alleging concerted actions by the affiliates frustrating the FERC's regulation of Transco. The alleged actions are related to offers of gathering service by WFS and its subsidiaries on the deregulated North Padre Island offshore gathering system. In September 2002, the FERC issued an order reasserting jurisdiction over that portion of the North Padre Island facilities previously transferred to WFS. The FERC also determined an unbundled gathering rate for service on these facilities which is to be collected by Transco. On July 13, 2004, the Court of Appeals reversed the FERC's decision, ruling that FERC's attempt to impose regulated rates was without legal basis.

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. 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 September 30, 2004. We will be filing a brief on exceptions to the initial decisions to both the FERC and RCA on November 16, 2004, and reply briefs are due on February 1, 2005. Decisions from the Commissions will then be issued, likely before the end of 2005. It is unlikely that we will be required to make any payments with respect to this matter until sometime after the Commission decisions.

Deepwater construction litigation

On February 12, 2004, Technip Offshore Contractors, Inc. (TOCI) served WFS, as agent for Williams Fields Services — Gulf Coast Company, L.P. and Williams Oil Gathering, L.L.C., with a lawsuit brought in federal court in Houston, Texas. TOCI alleges breach of its contract with us for the construction of export pipelines connected to the Devils Tower Spar in the Gulf of Mexico. TOCI seeks acceleration of our obligation to pay amounts held as retention and payment of almost $10 million for the value of disputed change orders. We have filed counterclaims seeking approximately $7 million arising from damages suffered due to TOCI's breaches of the contract, including liquidated delay damages. The litigation is in the early stages of discovery. On October 21, 2004, we partially settled the litigation with TOCI, which resulted in the release of the retention amounts and of a lien and in the delivery of various documents and commitments by TOCI. In addition, TOCI posted a letter of credit assuring its completion of certain regulatory approvals. Each party also posted letters of credit covering the value of remaining claims against it. The remaining claims to be litigated total approximately $10 million by TOCI against us and approximately $7 million by us against TOCI.

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 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 of bad faith which could potentially triple the damage award. The verdict is not yet final pending post-trial motions, but we expect to appeal the verdict if it is not set aside by the court.

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 are engaged in discussions with the joint interest owner regarding proper adjustment calculations, and we have proposed to settle these disputes for approximately $11.3 million plus interest of $3 million. We are in the early states of review of additional, unsubstantiated claims recently received from the joint interest owner. These additional claims total approximately $12 million.

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 September 30, 2004, 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.

Notes (Continued)

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 September 30, 2004, Power’s estimated committed payments under these contracts are approximately $85 million for the remainder of 2004, range from approximately $398 million to $425 million annually through 2017 and decline over the remaining five years to $59 million in 2022. Total committed payments under these contracts over the next eighteen years are approximately $6.4 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 exceed the minimum purchase price.

In connection with the construction of a joint venture pipeline project, we guaranteed, through a put agreement, certain portions of the joint venture’s project financing in the event of nonpayment by the joint venture. Our potential liability under this guarantee ranges from zero percent to 100 percent of the outstanding project financing, depending on our ability and the other project member’s ability to meet certain performance criteria. As of September 30, 2004, the total outstanding project financing is $32.8 million. While our maximum potential liability is the full amount of the financing, based on an executed Memorandum of Agreement (MOA), our exposure has been significantly reduced. On March 8, 2004, we entered into the MOA, in which the partner in the joint venture assumed 100 percent of project development costs to date as well as responsibility for any ongoing additional costs, pending a final determination of whether the project will go forward. Based on the MOA and the current status of the project, it is highly unlikely that any obligation would be incurred with respect to the project. The put agreement expires in March 2005. We have not accrued any amounts related to the guarantee at September 30, 2004.

We have guaranteed commercial letters of credit totaling $17 million on behalf of an equity method investee. These expire in January 2005, and have no carrying value.

We have provided guarantees in the event of nonpayment by our previously owned communications subsidiary, WilTel, on certain lease performance obligations that extend through 2042 and have a maximum potential exposure of approximately $50 million at September 30, 2004. Our exposure declines systematically throughout the remaining term of WilTel’s obligations. The carrying value of these guarantees is approximately $45 million at September 30, 2004 and is recorded as a non-current liability.

We have provided guarantees on behalf of certain partnerships in which we have an equity ownership interest. These generally guarantee operating performance measures and the maximum potential future exposure cannot be determined. These guarantees continue until we withdraw from the partnerships. No amounts have been accrued at September 30, 2004.

Notes (Continued)

14. Comprehensive income (loss)

Comprehensive income (loss) from both continuing and discontinued operations is as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2004	2003	2004	2003
	(Millions)		(Millions)	
Net income (loss)	$ 98.6	$106.3	$ 90.3	$(438.5)
Other comprehensive income (loss):				
Unrealized gains on securities	—	.5	—	.7
Net realized (gains) losses on securities	—	(13.5)	3.0	(13.5)
Unrealized gains (losses) on derivative instruments	(227.9)	169.4	(496.3)	(280.8)
Net reclassification into earnings of derivative instrument (gains) losses	52.4	(13.3)	150.4	10.5
Foreign currency translation adjustments	18.3	2.3	6.8	55.9
Minimum pension liability adjustment	(.3)	.2	.4	1.8
Other comprehensive income (loss) before taxes	(157.5)	145.6	(335.7)	(225.4)
Income tax benefit (provision) on other comprehensive income (loss)	66.7	(54.9)	130.4	107.5
Other comprehensive income (loss)	(90.8)	90.7	(205.3)	(117.9)
Comprehensive income (loss)	$ 7.8	$197.0	$(115.0)	$(556.4)

15. 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 previously reported within the International and Petroleum Services segments.

Due in part to FERC Order 2004, management and decision-making control of certain activities were transferred from our Midstream segment. Certain regulated gas gathering assets were transferred from our Midstream segment to our Gas Pipeline segment effective June 1, 2004, and our equity method investment in the Aux Sable gas processing plant and related business were transferred from our Midstream segment to our Power segment effective September 21, 2004. Consequently, the results of operations were similarly reclassified. All periods presented reflect these classifications.

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.

Power has entered into 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.

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.

Notes (Continued)

15. 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	Other	Eliminations	Total
				(Millions)			
Three months ended September 30, 2004							
Segment revenues:							
External	$2,338.8	$318.1	$ (22.2)	$735.8	$ 2.3	$ —	$3,372.8
Internal	249.9	2.9	231.5	10.6	4.4	(499.3)	—
Total segment revenues	2,588.7	321.0	209.3	746.4	6.7	(499.3)	3,372.8
Less intercompany interest rate swap loss	(15.5)	—	—	—	—	15.5	—
Total revenues	$2,604.2	$321.0	$209.3	$746.4	$ 6.7	$(514.8)	$3,372.8
Segment profit	$ 109.3	$148.8	$ 70.1	$105.0	$ 2.4	$ —	$ 435.6
Less:							
Equity earnings (losses)	.6	11.4	2.6	1.4	(.1)	—	15.9
Intercompany interest rate swap loss	(15.5)	—	—	—	—	—	(15.5)
Segment operating income	$ 124.2	$137.4	$ 67.5	$103.6	$ 2.5	$ —	435.2
General corporate expenses							(24.2)
Consolidated operating income							$ 411.0
Three months ended September 30, 2003							
Segment revenues:							
External	$3,729.2	$329.4	$ (14.6)	$696.3	$ 3.1	$ —	$4,743.4
Internal	169.2	4.6	183.3	5.5	7.9	(370.5)	—
Total segment revenues	3,898.4	334.0	168.7	701.8	11.0	(370.5)	4,743.4
Less intercompany interest rate swap income	10.0	—	—	—	—	(10.0)	—
Total revenues	$3,888.4	$334.0	$168.7	$701.8	$11.0	$(360.5)	$4,743.4
Segment profit	$ 37.2	$141.5	$ 58.8	$ 77.3	$ 4.1	$ —	$ 318.9
Less:							
Equity earnings (losses)	(1.1)	6.0	2.5	—	(.6)	—	6.8
Income from investments	6.6	—	—	11.0	—	—	17.6
Intercompany interest rate swap income	10.0	—	—	—	—	—	10.0
Segment operating income	$ 21.7	$135.5	$ 56.3	$ 66.3	$ 4.7	$ —	284.5
General corporate expenses							(17.8)
Consolidated operating income							$ 266.7

	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids	Other	Eliminations	Total
				(Millions)			
Nine months ended September 30, 2004							
Segment revenues:							
External	$ 6,561.4	$ 999.3	$ (56.3)	$1,975.4	$ 7.2	$ —	$ 9,487.0
Internal	655.8	11.7	619.8	28.8	19.1	(1,335.2)	—
Total segment revenues	7,217.2	1,011.0	563.5	2,004.2	26.3	(1,335.2)	9,487.0
Less intercompany interest rate swap loss	(16.6)	—	—	—	—	16.6	—
Total revenues	$ 7,233.8	$1,011.0	$563.5	$2,004.2	$ 26.3	$(1,351.8)	$ 9,487.0
Segment profit (loss)	$ 121.1	$ 429.0	$164.9	$ 312.1	$(20.6)	$ —	$ 1,006.5
Less:							
Equity earnings (losses)	.4	20.4	8.7	9.1	(.4)	—	38.2
Loss from investments	—	(1.0)	—	(.3)	(17.3)	—	(18.6)
Intercompany interest rate swap loss	(16.6)	—	—	—	—	—	(16.6)
Segment operating income (loss)	$ 137.3	$ 409.6	$156.2	$ 303.3	$ (2.9)	$ —	1,003.5
General corporate expenses							(84.5)
Consolidated operating income							$ 919.0
Nine months ended September 30, 2003							
Segment revenues:							
External	$10,115.0	$ 982.7	$ (27.5)	$2,032.4	$ 29.2	$ —	$13,131.8
Internal	482.5	21.6	640.3	37.0	29.9	(1,211.3)	—
Total segment revenues	10,597.5	1,004.3	612.8	2,069.4	59.1	(1,211.3)	13,131.8
Less intercompany interest rate swap loss	(12.6)	—	—	—	—	12.6	—
Total revenues	$10,610.1	$1,004.3	$612.8	$2,069.4	$ 59.1	$(1,223.9)	$13,131.8
Segment profit (loss)	$ 236.1	$ 407.3	$351.3	$ 247.3	$(42.8)	$ —	$ 1,199.2
Less:							
Equity earnings (losses)	(5.3)	9.8	7.1	(1.8)	2.4	—	12.2
Income (loss) from investments	(1.9)	.1	—	15.8	(42.5)	—	(28.5)
Intercompany interest rate swap loss	(12.6)	—	—	—	—	—	(12.6)
Segment operating income (loss)	$ 255.9	$ 397.4	$344.2	$ 233.3	$ (2.7)	$ —	1,228.1
General corporate expenses							(62.5)
Consolidated operating income							$ 1,165.6

15. Segment disclosures (Continued)

	Total Assets	
	September 30, 2004	December 31, 2003*
	(Millions)	
Power	$10,093.0	$ 8,732.9
Gas Pipeline	7,438.1	7,314.3
Exploration & Production	5,455.5	5,347.4
Midstream Gas & Liquids	3,951.8	3,990.3
Other	3,535.4	6,928.7
Eliminations	(4,983.0)	(6,078.2)
	25,490.8	26,235.4
Discontinued operations	68.3	786.4
Total	$25,559.1	$27,021.8

* Certain amounts have been reclassified as described in Note 2.

16. Recent accounting standards

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, as restated and amended, the SEC staff, in a letter to the EITF Chairman, questioned whether leased mineral rights should be presented as intangible assets rather than property, plant and equipment. In March 2004, the EITF reached a consensus that all mineral rights should be considered tangible assets for accounting purposes. In September 2004, the FASB issued a Staff Position that supported the consensus of the EITF. Therefore, no reclassification will be required.

In March 2004, the FASB issued an exposure draft of an accounting standard entitled “Share-Based Payment” to amend FASB Statement No. 123, “Accounting for Stock-Based Compensation”, and No. 95, "Statement of Cash Flows.” At its October 13, 2004 meeting, the Board concluded that the final statement would be effective for any interim or annual period beginning after June 15, 2005. At this time, we continue to account for our stock-based compensation plans under APB Opinion No. 25 while applying the proforma disclosure requirements of SFAS No. 148 (see Note 9).

In May 2004, the FASB issued FSP No. FAS 106-2, “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.” This guidance is effective for us beginning in third-quarter 2004 and supersedes FSP No. FAS 106-1. See Note 8 for additional information regarding this Issue, including the implementation effect for the three and nine months ended September 30, 2004.

EITF Issue No. 03-1, “The Meaning of Other Than Temporary Impairment and Its Application to Certain Investments,” contains recognition and measurement guidance that must be applied to investment impairment evaluations. Specifically, the Issue provides guidance to determine whether an investment is impaired and whether that impairment is other than temporary. The Issue applies to debt and equity securities, except equity securities accounted for under the equity method. The FASB is currently considering implementation guidance for the measurement and recognition provisions for this Issue and has delayed implementation. This Issue is required to be adopted on a prospective basis. We will continue to monitor this Issue to determine its potential impact to our Consolidated Balance Sheet and Consolidated Statement of Operations.

ITEM 2

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

Recent Events and Company Outlook

In February 2003, we outlined our planned business strategy in response to the events that significantly impacted the energy sector and our company during late 2001 and much of 2002, including the collapse of Enron and the severe decline of the telecommunications industry. The plan focused on migrating to an integrated natural gas business comprised of a strong, but smaller, portfolio of natural gas businesses; reducing debt; and increasing our liquidity through asset sales, strategic levels of financing and reductions in operating costs. The plan was designed to address near-term and medium-term debt and liquidity issues, to de-leverage the company with the objective of returning to investment grade status, and to develop a balance sheet and cash flows capable of supporting and ultimately growing our remaining businesses.

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003 we successfully executed certain critical components of our plan during 2003. Key execution steps for 2004 and beyond included the completion of planned asset sales; additional reductions of our SG&A costs; the replacement of our cash-collateralized letter of credit and revolver facility with facilities that do not encumber cash; and continuation of our efforts to exit from the Power business (see below).

Asset sales during 2004 were expected to generate proceeds of approximately $800 million. In first-quarter 2004, we completed the sale of our Alaska refinery and related assets for approximately $304 million. We completed the sale of three straddle plants in western Canada on July 28, 2004, for net proceeds of approximately $544 million (see Note 6 of Notes to Consolidated Financial Statements).

As part of our planned strategy, on February 25, 2004, our Exploration & Production segment amended its $500 million secured note facility, which was originally due May 30, 2007. The amendment provided more favorable terms including a lower interest rate and an extension of the maturity by one year (see Note 12 of Notes to Consolidated Financial Statements).

On March 15, 2004, we retired $679 million of senior unsecured 9.25 percent notes due March 15, 2004. The amount represented the outstanding balance remaining after the fourth-quarter 2003 tender which retired $721 million of the original $1.4 billion balance.

In April 2004, we entered into two new unsecured credit facilities totaling $500 million, which will be used primarily for issuing letters of credit. During April 2004, use of these facilities released approximately $500 million of restricted cash, restricted investments and margin deposits. Also, on May 3, 2004, we entered into a new three-year, $1 billion secured revolving credit facility. In August 2004, we expanded the credit facility by an additional $275 million. The revolving facility is secured by certain Midstream assets and a guarantee from WGP (see Note 12 of Notes to Consolidated Financial statements).

In May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of a specified series of our outstanding notes and debentures. We accepted $1.17 billion of the notes for purchase. In May 2004, we also repurchased debt of approximately $255 million of various maturities on the open market (see Note 12 in Notes to Consolidated Financial Statements). Our repurchase of these notes served to decrease debt and will result in reduced annual interest expense.

In August 2004, we made cash tender offers and consent solicitations for all of our 8.625 percent senior notes due 2010. We accepted $793 million of the notes for purchase.

Long-term debt, excluding the current portion, at September 30, 2004 was approximately $8.7 billion, compared to approximately $11 billion at December 31, 2003.

Power Business Status

In mid-2002, we initiated a strategy of exiting the Power business and have worked with financial advisors to assist with this effort. However, the number of financially viable parties expressing an interest in purchasing the entire business was limited. Additionally, the current and near term view of the wholesale power market, which we interpret as depressed, has strongly influenced these parties’ view of value and related risk associated with this business.

In September 2004, our Board of Directors approved the decision to retain Power and end our efforts to exit that business. Several factors affected our decision to retain the business, including:

- the cash flow expected to be generated by the business (Power has contracts in place expected to generate cash in amounts that substantially cover its obligations through 2010);
- the negative effect of depressed wholesale power markets on the marketability of the Power segment; and
- our progress over the last two years in reducing the risk of and increasing the certainty of cash flow from long-term power contracts.

We will continue our current program of managing this business to minimize financial risk and maximize cash flow associated with our long-term contracts.

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 6 of Notes to Consolidated Financial Statements):

- retail travel centers concentrated in the Midsouth, part of the previously reported Petroleum Services segment;
- refining and marketing operations in the Midsouth, including the Midsouth refinery, part of the previously reported Petroleum Services segment;
- Texas Gas Transmission Corporation, previously one of Gas Pipeline's segments;
- natural gas properties in the Hugoton and Raton basins, previously part of the Exploration & Production segment;
- bio-energy operations, part of the previously reported Petroleum Services segment;
- our general partnership interest and limited partner investment in Williams Energy Partners, previously the Williams Energy Partners segment;
- the Colorado soda ash mining operations, part of the previously reported International segment;
- certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta, previously part of the Midstream segment;
- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment;
- Gulf Liquids New River Project LLC, previously part of the Midstream segment; and
- the straddle plants in western Canada, previously part of the Midstream segment.

Management and decision-making control of certain activities have been transferred between segments. Consequently, the results of operations have been similarly reclassified. All periods presented reflect these classifications.

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 2003 Annual Report on Form 10-K, as restated and amended.

Management's Discussion and Analysis (Continued)

Results of operations

Consolidated overview

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

	Three months ended September 30,			Nine months ended September 30,		
	2004	2003	% Change from 2003 (1)	2004	2003	% Change From 2003 (1)
	(Millions)			(Millions)		
Revenues	$3,372.8	$4,743.4	-29%	$9,487.0	$13,131.8	-28%
Costs and expenses:						
Costs and operating expenses	2,854.5	4,387.6	+35%	8,202.7	11,836.0	+31%
Selling, general and administrative expenses	87.9	96.1	+9%	254.2	317.1	+20%
Other (income) expense — net	(4.8)	(24.8)	-81%	26.6	(249.4)	NM
General corporate expenses	24.2	17.8	-36%	84.5	62.5	-35%
Total costs and expenses	2,961.8	4,476.7	+34%	8,568.0	11,966.2	+28%
Operating income	411.0	266.7	+54%	919.0	1,165.6	-21%
Interest accrued — net	(196.3)	(264.9)	+26%	(657.2)	(1,000.4)	+34%
Interest rate swap income (loss)	(4.0)	2.5	NM	(5.3)	(6.4)	+17%
Investing income	9.2	40.6	-77%	31.2	43.7	-29%
Early debt retirement costs	(155.1)	—	NM	(252.4)	—	NM
Minority interest in income of consolidated subsidiaries	(5.2)	(5.6)	+7%	(16.0)	(15.1)	-6%
Other income — net	4.9	3.7	+32%	19.7	39.7	-50%
Income from continuing operations before income taxes and cumulative effect of change in accounting principles	64.5	43.0	+50%	39.0	227.1	-83%
Provision for income taxes	48.4	23.0	-110%	42.4	136.5	+69%
Income (loss) from continuing operations	16.1	20.0	-20%	(3.4)	90.6	NM
Income from discontinued operations	82.5	86.3	-4%	93.7	232.2	-60%
Income before cumulative effect of change in accounting principles	98.6	106.3	-7%	90.3	322.8	-72%
Cumulative effect of change in accounting principles	—	—	—	—	(761.3)	+100%
Net income (loss)	98.6	106.3	-7%	90.3	(438.5)	NM
Preferred stock dividends	—	—	—	—	29.5	+100%
Income (loss) applicable to common stock	$ 98.6	$ 106.3	-7%	$ 90.3	$ (468.0)	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.

Three Months Ended September 30, 2004 vs. Three Months Ended September 30, 2003

The $1.4 billion decrease in revenues is due primarily to decreased revenues at our Power segment. Power revenues decreased approximately $1.3 billion due primarily to lower power sales volumes, decreased crude and refined product realized revenues, and decreased interest rate portfolio realized revenues. Slightly offsetting this decrease is an increase in Midstream's revenues of $44.6 million and an increase in Exploration & Production's revenues of $40.6 million.

The $1.5 billion decrease in costs and operating expenses is due primarily to decreased costs and operating expenses at Power. The decrease at Power is due primarily to lower power purchase volumes and lower crude and refined product costs.

The $8.2 million decrease in selling, general and administrative expenses is due primarily to reduced staffing levels at Power reflective of our previous strategy to exit this business.

Other (income) expense — net, within operating income, in 2003 includes a $13 million gain from the sale of a Power contract, a $9.2 million gain from the sale of blending assets and $7.2 million of income related to a favorable liability adjustment at Transco, partially offset by a $12.9 million write-off of tax receivables associated with Power's European operations.

The $6.4 million increase in general corporate expenses is due primarily to transition costs associated with the outsourcing of certain activities, the absence of certain favorable expense adjustments in 2003 and costs associated with Sarbanes-Oxley Act compliance activities.

The $68.6 million decrease in interest accrued — is primarily due to lower average borrowing levels.

We entered into interest rate swaps with external counterparties primarily in support of the energy-trading portfolio (see Note 15 of Notes to Consolidated Financial Statements). The change in fair market value of these swaps was $6.5 million more unfavorable in 2004 than 2003 due to falling interest rates in 2004 compared to rising interest rates in 2003. The total notional amount of these swaps was approximately $300 million at September 30, 2004 and September 30, 2003.

The $31.4 million decrease in investing income is due primarily to:

- a $15.7 million impairment of an international cost-based investment in 2004;
- the absence in 2004 of a $13.5 million gain on the sale of marketable equity securities in 2003;
- the absence in 2004 of an $11 million gain on the sale of our equity interest in West Texas LPG Pipeline, L.P. in 2003; and
- partially offset by the absence in 2004 of a $5.6 million impairment of our equity interest in Aux Sable in 2003.

Early debt retirement costs for 2004 includes premiums, fees and expenses related to the cash tender offer and consent solicitations that we completed in the third quarter.

Other income — net, below operating income, includes a $5 million net loss in 2004 and a $6.5 million net loss in 2003 related to a foreign currency transaction gain on a Canadian dollar denominated note receivable and an offsetting derivative loss on a forward contract to fix the U.S. dollar principal cash flows from the note receivable. The note receivable was repaid in July 2004 with proceeds from the sale of the Canadian straddle plants and the related forward contract was terminated.

The provision for income taxes was unfavorable by $25.4 million due primarily to higher pre-tax income in 2004. The effective income tax rate for 2004 is significantly greater than the federal statutory rate due primarily to the effect of state income taxes (including no state income tax benefit recognized for state net operating losses) and net foreign operations. The effective income tax rate for 2003 is greater than the federal statutory rate due primarily to the effect of state income taxes, net foreign operations and an accrual for income tax contingencies.

Income from discontinued operations decreased $3.8 million. The decrease is due primarily to the $134.4 million charge associated with certain Quality Bank litigation matters (see Note 13 of Notes to Consolidated Financial Statements) and the absence in 2004 of the $72.3 million net gain on the sale of discontinued operations in 2003, partially offset by an $189.8 million pre-tax gain on the sale of three straddle plants in western Canada in 2004, The 2003 net gain on the sales of discontinued operations includes:

- an $86.6 million gain on the sale of certain Canadian liquids operations,
- a $9 million reduction of the $304.6 million third-quarter 2002 pre-tax gain on the sale of our 98 percent interest in Mid- America Pipeline and 98 percent of our 80 percent ownership interest in Seminole Pipeline, and
- a $4.2 million loss on the sale of the soda ash mining facility located in Colorado.

Nine Months Ended September 30, 2004 vs. Nine Months Ended September 30, 2003

The $3.6 billion decrease in revenues is due primarily to decreased revenues at Power. Power revenues decreased approximately $3.4 billion due primarily to lower power sales volumes, decreased crude and refined product realized revenues and decrease in net unrealized gains on power and natural gas derivative contracts. In addition, Midstream's revenues decreased $65.2 million and Exploration & Production's revenues decreased $49.3 million.

The $3.6 billion decrease in costs and operating expenses is due primarily to decreased costs and operating expenses at Power. The decrease at Power is due primarily to lower power purchase volumes and lower crude and refined products costs.

The $62.9 million decrease in selling, general and administrative expenses is due primarily to reduced staffing levels at Power reflective of our previous strategy to exit this business. Also contributing to the decrease at Power was the absence in 2004 of $13.6 million of expense related to the accelerated recognition of deferred compensation during 2003.

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

- an $11.3 million loss provision related to an ownership dispute on prior period production included in the Exploration & Production segment,
- a $9 million write-off of previously-capitalized costs on an idled segment of Northwest's system, and
- $6.1 million in fees related to the sale of certain receivables to a third party.

Other (income) expense — net, within operating income, in 2003 includes:

- an $188 million gain from the sale of a Power contract,
- $96.4 million in net gains from the sale of Exploration & Production's interests in certain natural gas properties,
- a $25.5 million charge at Northwest to write-off capitalized software development costs for a service delivery system,
- a $20 million charge related to a settlement by Power with the Commodity Futures Trading Commission (CFTC) (see Note 13 of Notes to Consolidated Financial Statements), and
- a $9.2 million gain on sale of blending assets at the Other segment.

The $22 million increase in general corporate expenses is due primarily to increased third-party costs associated with Sarbanes-Oxley Act compliance activities and with efforts to evaluate and implement certain cost reduction strategies through internal initiatives and outsourcing of certain services.

The $343.2 million decrease in interest accrued — net includes:

- $205 million lower interest expense and fees at Exploration & Production due primarily to the May 2003 prepayment of the RMT note payable;
- an $88 million decrease reflecting lower average borrowing levels;
- a $19 million decrease reflecting lower average interest rates on long-term debt;
- $40 million lower amortization expense related to deferred debt issuance costs, primarily due to the reduction of debt;
- the absence in 2004 of $12 million of interest expense within Power related to a FERC ruling in 2003;
- the absence in 2004 of $10 million of interest expense related to a petroleum pricing dispute in 2003; and
- a $28.9 million decrease in capitalized interest, which partially offsets these decreases, due primarily to completion of certain Midstream projects in the Gulf Coast region.

The $12.5 million decrease in investing income includes:

- $42 million lower interest income at Power due primarily to a favorable adjustment in 2003 resulting from certain 2003 FERC proceedings;
- a $15.7 million impairment of an international cost-based investment in 2004;
- the absence in 2004 of a $13.5 million gain on the sale of marketable equity securities in 2003;
- the absence in 2004 of an $11 million gain on the sale of the West Texas LPG Pipeline L.P. in 2003;
- $9.5 million lower interest income on advances to Longhorn that were subsequently exchanged for preferred stock;
- the absence in 2004 of a $42.4 million impairment of our investment in equity and debt securities of Longhorn in 2003, partially offset by a $10.8 million impairment of our investment in equity securities of Longhorn in 2004 and $6.5 million net unreimbursed Longhorn recapitalization advisory fees in 2004;
- the absence in 2004 of a $13.2 million impairment of our cost-based investments in Algar Telecom S.A. and a $13.5 million impairment of a cost-based investment in a company holding phosphate reserves in 2003;
- $14.6 million higher equity earnings from Discovery due primarily to the absence of unfavorable accounting adjustments recorded at the partnership in 2003; and
- the absence in 2004 of a $14.1 million impairment of our equity interest in Aux Sable in 2003.

Early debt retirement costs for 2004 include:

- premiums, fees and expenses related to the May 2004 debt repurchase and the cash tender offer and consent solicitations that we completed in the second quarter; and
- premiums, fees and expenses related to the third quarter of 2004 cash tender offer.

Other income — net, below operating income, includes a $1.7 million net gain in 2004 and a $13.9 million net gain in 2003 related to a foreign currency transaction loss on a Canadian dollar denominated note receivable and an offsetting derivative gain on a forward contract to fix the U.S. dollar principal cash flows from the note receivable. The note receivable was repaid in July 2004 with proceeds from the sale of the Canadian straddle plants and the related forward contract was terminated. Other income — net also decreased $10.1 million due to lower capitalization of interest on internally generated funds related to various capital projects at FERC regulated entities.

The provision for income taxes was favorable by $94.1 million due primarily to a lower pre-tax income in 2004. The effective income tax rate for 2004 is significantly greater than the federal statutory rate due primarily to the effect of state income taxes and net foreign operations. The effective income tax rate for 2003 is greater than the federal statutory rate due primarily to the effect of state income taxes, net foreign operations, an accrual for income tax contingencies, nondeductible expenses, the financial impairment of certain investments and capital losses generated for which valuation allowances were established.

Income from discontinued operations decreased $138.5 million (see Note 6 of Notes to Consolidated Financial Statements). The decrease in the operating results from discontinued operations activities of $254.6 million is reflective of income (loss) from discontinued operations for the following operations:

- the $134.4 million charge to increase our accrued liability associated with certain Quality Bank litigation matters (see Note 13);
- the absence in 2004 of approximately $106 million of income (net of losses) from discontinued operations in 2003 of Canadian liquids, Williams Energy Partners, Bio-energy facilities, Raton Basin and Hugoton Embayment natural gas exploration and production properties, Texas Gas, Midsouth refinery and related assets and Williams travel centers;
- a decrease of approximately $40 million related to results of Canadian straddle plants and Alaska refining, retail and pipeline operations sold in 2004; and
- an increase of approximately $30 million related to improved results for Gulf Liquids New River Project LLC which is currently held for sale.

The 2004 net gain on sales of discontinued operations of $199.9 million includes:

- a $189.8 million gain on the sale of three straddle plants in western Canada; and
- a gain of $3.7 million on the sale of the Alaska refinery, retail and pipeline assets.

The 2003 net gain on sales of discontinued operations of $187.9 million includes:

- an $109 million impairment of Texas Gas Transmission;
- an $8 million impairment of the Alaska refinery, retail and pipeline assets;
- a $17.4 million impairment and $4.2 million loss on the sale of the soda ash mining facility located in Colorado;
- a $29.4 million gain on the sale of a refinery and other related operations located in Memphis, Tennessee, of which $24.7 million relates to the sale of an earn-out agreement that we retained following the sale of the assets;
- a $39.9 million gain on sale of certain natural gas exploration & production properties;
- a $6.4 million loss on sale of our Bio-energy operations;
- a $275.6 million gain on the sale of Williams Energy Partners;
- a $92.6 million impairment of Gulf Liquids;
- a $9 million reduction of the $304.6 million third-quarter 2002 pre-tax gain on the sale of our 98 percent interest in Mid-America Pipeline and 98 percent of our 80 percent ownership interest in Seminole Pipeline; and
- an $86.6 million gain on the sale of certain Canadian liquids operations.

The cumulative effect of change in accounting principles reduced net income for 2003 by $761.3 million due to a $762.5 million charge related to the adoption of EITF 02-3, slightly offset by $1.2 million related to the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" (see Note 3 of Notes to Consolidated Financial Statements).

In June 2003, we redeemed all of our outstanding 9.875 percent cumulative-convertible preferred shares. Thus, no preferred dividends were paid in 2004.

Results of operations — segments

We are currently organized into the following segments: Power, Gas Pipeline, Exploration & Production, Midstream and Other. Other primarily consists of corporate operations and certain continuing operations previously reported within the International and Petroleum Services segments. Our management currently evaluates performance based on segment profit (loss) from operations (see Note 15 of Notes to Consolidated Financial Statements).

Prior period amounts have been restated to reflect all segment changes. The following discussions relate to the results of operations of our segments.

Power

Overview of nine months ended September 30, 2004

As described below, past efforts to exit from the Power business, combined with liquidity constraints, and the effect of price changes on derivative contracts significantly influenced Power's operating results for the first three quarters of 2004.

Prior to September 2004, Power continued to focus on 1) terminating or selling all or portions of the portfolio, 2) maximizing cash flow, 3) reducing risk, and 4) managing existing contractual commitments. These efforts were consistent with our 2002 decision to sell all or portions of Power's portfolio. The decrease in revenues, costs and selling, general and administrative expenses reflects our past efforts to exit the Power business.

In September 2004, we announced our decision to continue operating the Power business and cease efforts to exit that business. As a result, Power will focus on its objectives of realizing expected cash flows, executing new contracts to hedge its portfolio and providing functions that support Williams' natural gas businesses.

Key factors that 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 economically 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
- inability of counterparties to perform under contractual obligations due to their own credit constraints.

Outlook for the remainder of 2004

As a result of our past intent to exit the Power business, Power did not previously qualify for hedge accounting. However, with the decision to retain the business, Power became eligible for hedge accounting under SFAS 133 and expects to elect hedge accounting on a prospective basis beginning October 1, 2004 for certain qualifying derivative contracts. The estimated fair value of the contracts expected to qualify for hedge accounting is in excess of $900 million at September 30, 2004. Prior to the election of hedge accounting, Power was required to report changes in the forward fair value of its derivative contracts in earnings as unrealized gains or losses. Upon election of cash flow hedge accounting, to the extent that the hedges are effective, prospective changes in the forward fair value of the hedges will be reported as changes in other comprehensive income in the equity section of the balance sheet, and then reclassified to earnings when the underlying hedged transactions (i.e. power sales and gas purchases) affect earnings. As a result, Power's future results associated with these contracts should be less volatile. However, not all of Power's derivative contracts will qualify for hedge accounting. Power will continue to report changes in the fair value of those 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 continue to be reported in earnings. The derivative contracts qualifying for hedge accounting have significant fair value which has been recognized in earnings as unrealized gains or losses prior to October 1, 2004. Therefore, it is expected that future operating results will reflect losses from the underlying transactions that have been hedged by the derivatives, but will not reflect the positive value from the derivative hedging positions since such positive value has already been recognized in prior periods. However, cash flows from Power's portfolio will reflect the net amount from both the hedged transactions and the hedges. The adoption of hedge accounting will not affect the balance sheet presentation of derivatives, nor the timing of cash flows associated with the hedges and the underlying hedged transactions.

Even with the adoption of hedge accounting, some variability in Power's unrealized earnings will remain as a result of:

- market movements of interest rate derivatives, which do not qualify for hedge accounting;
- market movements of commodity-based derivatives which do not qualify for hedge accounting; and
- ineffectiveness of cash flow hedges.

The fair value of Power's tolling, full requirements, transportation, storage and transmission contracts is not reflected in the balance sheet since these contracts are not derivatives. Some of these underlying contracts have a negative fair value and, therefore, 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 September 30,		Nine months ended September 30,	
	2004	2003	2004	2003
	(Millions)		(Millions)	
Segment revenues	$2,588.7	$3,898.4	$7,217.2	$10,597.5
Segment profit	$ 109.3	$ 37.2	$ 121.1	$ 236.1

Three months ended September 30, 2004 vs. three months ended September 30, 2003

The approximately $1.3 billion decrease in revenues includes a $1.6 billion decrease in realized revenues partially offset by a $242 million increase in net forward unrealized mark-to-market gains.

Realized revenues represent 1) revenue from sale of commodities or completion of energy-related services, and 2) gains and losses from the net financial settlement of derivative contracts. The $1.6 billion decrease in realized revenues is due to a $1.3 billion decrease in power and natural gas realized revenues, a $160 million decrease in crude and refined products realized revenues, and a $61 million decrease in interest rate portfolio realized revenues.

Power and natural gas revenues decreased primarily due to a 51 percent decrease in power sales volumes and a two percent decrease in power sales prices. Sales volumes decreased because Power did not replace certain long-term physical contracts that expired or were terminated in 2003, primarily due to a lack of market liquidity and past efforts to reduce our commitment to the Power business. In addition, results for the third quarter of 2003 include a realized gain of $126.8 million based on the terms of an agreement to terminate a derivative contract. The decrease in crude and refined products realized revenues is primarily due to the sale of the refined products business in third-quarter 2004 and other past efforts to exit this line of business. The decrease in realized revenues from Power’s interest rate portfolio reflects the impact of a decline in third-quarter 2004 interest rates in contrast to a rise in third-quarter 2003 interest rates.

Net forward unrealized mark-to-market gains and losses represent changes in the fair value of derivative contracts with a future settlement or delivery date. In third-quarter 2004, Power had unrealized mark-to-market gains of $187 million, an increase of $242 million from third-quarter 2003. The $242 million increase is due to a $245 million increase in net unrealized gains on power and natural gas derivative contracts, a $7 million increase in net unrealized gains on crude and refined product derivative contracts, partially offset by a $10 million decrease in the interest rate portfolio.

The increase in power and natural gas net forward unrealized mark-to-market gains is largely due to an increase in forward natural gas prices in third-quarter 2004 compared to a decrease in forward natural gas prices in the same period in 2003. This impact is partially offset by power price increases in third-quarter 2004 compared to price decreases during the same period in 2003. Because Power holds fixed price forward contracts to purchase natural gas and sell power, an increase in the forward natural gas price results in unrealized gains and an increase in forward power prices results in unrealized losses. Interest rate unrealized losses increased due to a decrease in forward interest rates in 2004 compared to an increase in 2003.

Power’s costs represent purchases of commodities and fees paid for energy related services. Costs decreased approximately $1.4 billion due to an approximately $1.2 billion decrease in power and natural gas costs and a $162 million decrease in crude and refined products costs. Power and natural gas costs decreased largely due to a 53 percent decrease in power purchase volumes and a 6 percent decrease in power prices. Purchase volumes decreased due primarily to the expiration or termination of certain long-term physical contracts in 2003. Crude and refined products costs decreased due to the sale of the refined products business in third-quarter 2004 and other past efforts to exit this line of business.

The $72.1 million increase in segment profit is due primarily to an increase in net forward unrealized mark-to-market gains. This increase was partially offset by an increase in realized losses.

Nine months ended September 30, 2004 vs. nine months ended September 30, 2003

The approximately $3.4 billion decrease in revenues includes an approximately $3.5 billion decrease in realized revenues, partially offset by a $119 million increase in forward unrealized mark-to-market gains.

The approximately $3.5 billion decrease in realized revenues is due to an approximately $2.8 billion decrease in power and natural gas realized revenues, a $679 million decrease in crude and refined products realized revenues, and a $24 million decrease in interest rate portfolio realized revenues.

Power and natural gas realized revenues decreased primarily due to a 47 percent decrease in power sales volumes, partially offset by a four percent increase in power price. Sales volumes decreased because Power did not replace certain long-term physical contracts that expired or were terminated in 2003, primarily due to a lack of market liquidity and past efforts to reduce our commitment to the Power business. In addition, results for 2003 include a realized gain of $126.8 million based on the terms of an agreement to terminate a derivative contract. Also, during the second quarter of 2003, Power corrected the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001, resulting in the recognition of approximately $108 million in revenues in the first three quarters of 2003 attributable to prior periods. Refer to Note 1 of Notes to Consolidated Financial Statements for further information. Additionally, power and natural gas revenues in 2003 include a $37 million loss for increased power rate refunds owed to the state of California as the result of FERC rulings, which partially offsets the general decrease discussed above. Crude and refined products revenues decreased primarily due to the sale of the crude gathering business in second-quarter 2004, the sale of the refined products business in third-quarter 2004 and the past efforts to exit this line of business. The decrease in realized revenues from Power's interest rate portfolio reflects the impact of a decline in interest rates during the first nine months of 2004 in contrast to a rise in rates over the same period during 2003.

For the first nine months of 2004, Power had net forward unrealized mark-to-market gains of $304 million, an increase of $119 million over the same period in 2003. The increase in unrealized gains is due to a $101 million increase in power and gas, a $5 million increase in crude and refined products and a $13 million increase in the interest rate portfolio. The increase in power and gas primarily results from an increase in power and natural gas forward prices. Natural gas forward prices increased by a larger amount in 2004 than in 2003, resulting in a larger unrealized forward gain on natural gas derivatives in 2004. This impact is partially offset by an increase in the forward power price that was larger in 2004 than in 2003. Because Power holds fixed price forward purchase contracts to purchase natural gas and sell power, an increase in the forward natural gas price results in unrealized gains and an increase in forward power prices results in unrealized losses. Also contributing to the increase was the absence in 2004 of unrealized losses of approximately $70 million recognized in first-quarter 2003 on contracts for which we elected the normal purchases and sales exception in second-quarter 2003.

Power's costs decreased $3.4 billion due to a decrease in power and natural gas costs of approximately $2.7 billion and a decrease in crude and refined products costs of $698 million. Power and natural gas costs decreased primarily due to a 49 percent decrease in power purchase volumes and a one percent decrease in power prices. Second-quarter 2004 reductions to liabilities of $10.4 million, associated with power marketing activities in California during 2000 and 2001, contributed to the decrease in costs discussed above. Costs in 2004 also reflect a $13 million payment made to terminate a non-derivative power sales contract, which partially offsets the decrease in power and natural gas costs. Crude and refined products costs decreased primarily due to the sale of the crude gathering business in 2003, the sale of the refined products business in third-quarter 2004, and other past efforts to exit this line of business.

Selling, general and administrative expenses decreased $51 million. Compensation expense declined $39 million, primarily as a result of staff reductions in prior years combined with the accelerated recognition in 2003 of certain deferred compensation arrangements. A $6.3 million reduction of allowance for bad debts resulting from the first-quarter 2004 settlement with certain California utilities and the absence of a $6.5 million bad debt charge associated with a termination settlement in second-quarter 2003 also contributed to the decrease.

Other (income) expense — net in 2003 includes a $188 million gain from the sale of an energy-trading contract and a $13.5 million gain from the sale of marketable equity securities partially offset by a $20 million charge for a settlement with the CFTC. Other (income) expense — net in 2004 includes $6.1 million in fees related to the sale of certain receivables to a third party.

The $115 million decrease in segment profit is primarily due to a decrease in realized revenues that was greater than the corresponding decrease in costs and changes in selling, general and administrative expenses and other (income) expense — net. These decreases are partially offset by the impact of an increase in net forward unrealized mark-to-market gains as discussed above.

Gas Pipeline

Overview of nine months ended September 30, 2004

In February 2004, Transco placed an expansion into service increasing capacity on its natural gas system by 54 MDth/d. As discussed below, Northwest made additional progress towards repairing and restoring a segment of its natural gas pipeline system in western Washington.

In August 2004, Transco filed an application with 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 MDth/d of firm natural gas transportation service in Transco's northeastern market area. The construction is scheduled to begin in the summer of 2005 and is expected to be placed into service in November 2005.

Effective June 1, 2004, and due in part to FERC Order 2004, management and decision-making control of certain regulated gas gathering assets was transferred from our Midstream segment to our Gas Pipeline segment. Consequently, the results of operations were similarly reclassified. All prior periods reflect these classifications.

Outlook for the remainder of 2004

In December 2003, we received an Amended Corrective Action Order (ACAO) from the U.S. Department of Transportation's Office of Pipeline Safety (OPS) regarding a segment of one of our natural gas pipelines in western Washington. The pipeline experienced two breaks in 2003 and we subsequently idled the pipeline segment until its integrity could be assured. The decision to idle the pipeline has not had a significant impact on our ability to meet market demand to date.

By June 2004, we had successfully completed our hydrostatic testing program and returned to service 111 miles of the 268 miles of pipe affected by the ACAO. That effort has restored 131 MDth/day of the 360 MDth/day of idled capacity and is anticipated to be adequate to meet most market conditions. The restored facilities will be monitored and tested as necessary until they are ultimately replaced. Total estimated testing and remediation costs are between $40 and $45 million, including approximately $9 million related to one segment of pipe that we determined not to return to service and therefore was written off in the second quarter.

As required by OPS, we plan to replace the pipeline's entire capacity by November 2006 to meet long-term demands. We conducted a reverse open season to determine whether any existing customers were willing to relinquish or reduce their capacity commitments to allow us to reduce the scope of pipeline replacement facilities, which resulted in 13 MDth/day of capacity being relinquished and incorporated into the replacement project. The total costs of the capacity replacement project are expected to be in the range of approximately $310 million to $360 million. The majority of these costs will be spent in 2005 and 2006. We anticipate filing a rate case to recover the capitalized costs relating to restoration and replacement of facilities following the in-service date of the replacement facilities.

Period-over-period results

	Three months ended September 30,		Nine months ended September 30,	
	2004	2003	2004	2003
	(Millions)		(Millions)	
Segment revenues	$ 321.0	$ 334.0	$ 1,011.0	$ 1,004.3
Segment profit	$ 148.8	$ 141.5	$ 429.0	$ 407.3

Three months ended September 30, 2004 vs. three months ended September 30, 2003

The $13 million, or four percent, decrease in Gas Pipeline revenues is due primarily to $8 million lower revenues associated with reimbursable costs, which are passed through to customers (partially offset in costs and operating expenses) and $7 million lower exchange imbalance settlements (offset in costs and operating expenses), partially offset by $4 million higher transportation revenues. The $4 million increase in transportation revenues is due primarily to $12 million higher revenue from expansion projects, partially offset by $8 million lower revenue from all other operations. The $12 million increase is due primarily to $10 million higher demand revenues at Northwest from an expansion project that became operational in October 2003 (Evergreen) and $2 million higher demand revenues on the Transco system resulting from expansion projects that became operational in November 2003 (Trenton-Woodbury) and February 2004 (Momentum Phase II). The $8 million decrease is due primarily to $4 million lower commodity revenue at Transco and $4 million lower short-term firm revenues at Northwest.

Costs and operating expenses decreased $20 million, or 12 percent, due primarily to $7 million lower gas exchange imbalance settlements (offset in revenues), $5 million lower recovery of reimbursable costs, which are passed through to customers (offset in revenues), a $4.5 million reduction of expense related to a correction to depreciation recognized in a prior period and the absence of a $4 million write-off of certain receivables at Transco in 2003. These decreases are partially offset by $4 million higher maintenance expenses and additional costs due to pipeline safety regulations.

Other (income) expense — net in 2003 includes $7.2 million of income at Transco resulting from a partial reduction of accrued liabilities for claims associated with certain producers as a result of settlements and court rulings (see Note 13 of Notes to Consolidated Financial Statements).

The $7.3 million, or five percent, increase in Gas Pipeline segment profit is due primarily to $20 million lower costs and operating expenses and $5.4 million higher equity earnings from our investment in Gulfstream Natural Gas System (Gulfstream) (included in Investing income (loss)). These items were partially offset by $13 million lower revenues and the absence of $7.2 million of income in 2003 resulting from a reduction of accrued liabilities discussed above.

Nine months ended September 30, 2004 vs. nine months ended September 30, 2003

The $6.7 million, or one percent, increase in Gas Pipeline revenues is due primarily to $28 million higher transportation revenues, partially offset by $16 million lower revenues associated with reimbursable costs, which are passed through to customers (substantially offset in costs and operating expenses) and $8 million lower revenues from the sale of environmental mitigation credits. The $28 million increase in transportation revenues is due primarily to $43 million higher revenue from expansion projects, partially offset by $15 million lower revenue from all other operations. The $43 million increase is due primarily to $29 million higher demand revenues at Northwest from an expansion project that became operational in October 2003 (Evergreen) and $14 million higher demand revenues on the Transco system resulting from new expansion projects that became operational in May 2003 (Momentum Phase I), November 2003 (Trenton-Woodbury) and February 2004 (Momentum Phase II). The $15 million decrease is due primarily to $5 million lower commodity revenues at Transco and $10 million lower short-term firm revenues at Northwest.

Costs and operating expenses increased $6 million, or one percent, due primarily to $13 million higher fuel expense at Transco reflecting a reduction in pricing differentials on the volumes of gas used in operations as compared to 2003, $10 million higher gas exchange imbalance settlements (offset in revenues), $9 million higher maintenance expenses and additional costs to comply with new pipeline safety regulations, $5 million in non-income related taxes and $3 million higher depreciation expense related to additional property, plant and equipment placed into service. These increases were partially offset by $14 million lower recovery of reimbursable costs which are passed through to customers (offset in revenues), an $8.5 million reduction of expense related to adjustments to depreciation recognized in a prior period, a $5 million reduction of depreciation, depletion and amortization expense related to environmental mitigation credits, the absence of a $4 million write-off of certain receivables at Transco in 2003 and a $4 million decrease in regulatory charges.

Other (income) expense — net in 2004 includes a $9 million charge for the write-off of previously-capitalized costs incurred on an idled segment of Northwest's system that we determined will not be returned to service. Other (income) expense — net in 2003 includes a $25.5 million charge at Northwest to write-off capitalized software development costs for a service delivery system following a decision not to implement and $7.2 million of income at Transco resulting from a partial reduction of accrued liabilities for claims associated with certain producers as a result of settlements and court rulings (see Note 13 of Notes to Consolidated Financial Statements).

The $21.7 million, or five percent, increase in Gas Pipeline segment profit is primarily due to the absence of the $25.5 million charge in 2003 discussed above, $10.6 million higher equity earnings (included in Investing income (loss)) and $6.7 million higher revenues. These increases were partially offset by the $9 million charge for the write-off of previously capitalized costs discussed above, the absence of the $7.2 million of income in 2003 resulting from a reduction of accrued liabilities discussed above, and the $6 million higher costs and operating expenses. The increase in equity earnings includes a $10.8 million increase in earnings from our investment in Gulfstream.

Exploration & Production

Overview of nine months ended September 30, 2004

Domestic average daily production volumes have increased 19 percent from the beginning of the year. The domestic average daily production for the quarter ending September 30, 2004 was approximately 535 million cubic feet of gas equivalent compared to 450 million cubic feet at the beginning of the year. The increase is directly related to an increased drilling program and shorter drilling cycle, particularly in the Piceance basin. Additional rigs also were added to the other core areas of the San Juan, Arkoma and Powder River basins. Partially offsetting these higher volumes are increased costs and losses on derivatives that do not qualify for hedge accounting. Operating costs are higher as a result of escalated overall production and maintenance activities among oil and gas producers, which has caused service companies to increase their fees.

Outlook for the remainder of 2004

Our expectations for the remainder of the year include:

- continuing our production volume growth with our increased development drilling program in our key basins; and
- achieving a 20 percent increase in production levels from the beginning of the year through the end of 2004.

Approximately 72 percent of our forecasted production for the remainder of 2004 is hedged at prices that average $3.76 per mcfe at a basin level.

Period-over-period results

The following discussions of the quarter-over-quarter and year-to-date comparative results primarily relate to our continuing operations. However, the results for 2003 include those operations that were sold during 2003 that did not qualify for discontinued operations reporting. Those properties consist of the Uinta and Denver Julesberg basins and certain additional properties in the Green River and San Juan basins. The operations classified as discontinued operations are the properties in the Hugoton and Raton basins.

	Three months ended September 30,		Nine months ended September 30,	
	2004	2003	2004	2003
	(Millions)		(Millions)	
Segment revenues	$209.3	$168.7	$563.5	$612.8
Segment profit	$ 70.1	$ 58.8	$164.9	$351.3

Three months ended September 30, 2004 vs. three months ended September 30, 2003

The $40.6 million, or 24 percent, increase in Exploration & Production’s revenues is primarily due to the $31 million increase in domestic production revenue reflecting higher production volumes and higher net realized average prices which include the effect of hedge positions. The remainder of the increase reflects an increase in revenues from gas management activities.

The increase in domestic production revenues reflects $21 million higher revenues associated with a 16 percent increase in production volumes and $10 million higher revenues associated with a six percent increase in net realized average prices for production sold. The increase in production volumes primarily results from an increase in the number of producing wells associated with our successful 2004 drilling program. We expect volumes to continue to increase during the remainder of the year as our development drilling program continues.

To minimize 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. Approximately 78 percent of domestic production in the third quarter of 2004 was hedged. These hedging decisions are made considering our overall commodity risk exposure.

Total costs and expenses increased $29 million, primarily reflecting the following:

- $9 million higher lease operating expense associated with the higher number of producing wells and the increase of well maintenance activities, higher labor and fuel costs and an increase in overhead payments to another operator;
- $11 million higher depreciation, depletion, and amortization expense, primarily as a result of higher production volumes as well as higher capitalized drilling costs consisting of increased prices for oil country tubular goods occurring in response to a tight worldwide steel market; and
- $6 million higher operating taxes primarily as a result of increased market prices and production volumes sold.

The $11.3 million increase in segment profit is due primarily to higher production revenues partially offset by higher operating costs as discussed above.

Nine months ended September 30, 2004 vs. nine months ended September 30, 2003

The $49.3 million, or 8 percent decrease in Exploration & Production's revenues is primarily due to $25 million lower income on derivative instruments that did not qualify for hedge accounting and $14 million lower domestic production revenues reflecting lower net realized average prices. The remainder of the decrease reflects a reduction in revenues from gas management activities and lower income from an affiliate's utilization of excess transportation capacity.

The decrease in domestic production revenues reflects $27 million lower revenues associated with a six percent decrease in net realized average prices for production sold, partially offset by $13 million higher revenues reflecting a three percent increase in net domestic production volumes. The increase in production volumes primarily results from an increase in the number of new producing wells.

Total costs and expenses increased $139 million which includes the absence of $95 million in net gains on sales of assets occurring in 2003. The remaining increase in operating costs and expenses primarily reflects:

- $8 million higher depreciation, depletion, and amortization expense as a result of increased volumes as well as increased capitalized drilling costs consisting of increased prices for oil country tubular goods occurring in response to a tight worldwide steel market;
- $17 million higher lease operating expense associated with the higher number of producing wells and an increase in well maintenance activities, higher labor and fuel costs, and an increase in overhead payments to another operator;
- $7 million higher operating taxes primarily as a result of increased market price and production volumes sold; and
- $11 million other (income) expense occurring in the second quarter of 2004 relating to a loss provision regarding an ownership dispute on prior period production.

The $186.4 million decrease in segment profit is due primarily to the absence of $95 million in net gains on the sales of assets in 2003, $14 million lower net production revenues reflecting decreased net realized average prices, $25 million lower income on derivative instruments that did not qualify for hedge accounting and the loss provision of $11 million, relating to an ownership dispute on prior period production as discussed above.

Midstream Gas & Liquids

Overview of nine months ended September 30, 2004

We continue to execute our strategy to invest in growth areas where we have large scale assets and divest non-core assets. Consistent with this strategy, we placed into service additional infrastructure in the deepwater offshore area of the Gulf of Mexico and expanded our Opal gas processing facility in Wyoming. In the deepwater Gulf of Mexico, the Devils Tower production handling facility, the Canyon Chief gas pipeline, and the Mountaineer oil pipeline began flowing product in May 2004, while the Gunnison oil pipeline volumes have been increasing since the first of the year. In July 2004, we closed the sale of our western Canadian Straddle Plants, which yielded net proceeds of approximately $544 million in U.S. funds. The pre-tax gain on sale of approximately $190 million was recognized in discontinued operations in the third quarter of 2004. With the completion of these sales, we achieved the cash generation goals for our asset sales program. However, we continue to negotiate with counterparties for the sale of Gulf Liquids.

During the first nine months of 2004, our businesses benefited from favorable commodity prices. Our gas processing facilities benefited from near record high NGL margins and operated at full capacity throughout most of the period. Our olefins business also benefited from improved fractionation and cracking margins. The olefins cracking margin represents the price difference between the ethane and propane feedstocks and the ethylene and propylene olefins products. Results for the third quarter were slightly offset by the impact of Hurricane Ivan and an accounting correction related to our recent deepwater assets (see below).

In September 2004, portions of our Gulf Coast operations were interrupted by Hurricane Ivan. The Mobile Bay gas processing plant, Canyon Station and Devils Tower platforms were each located in the path of the hurricane and incurred minor damage. As a result, Hurricane Ivan caused temporary shut-downs of both our facilities and producers' facilities, which reduced product flows resulting in lower segment profit of approximately $5 million in the third quarter of 2004. The majority of the repairs related to Hurricane Ivan will be covered by our insurance claim. Repairs to the Devils Tower facility were completed in October 2004 while other of our assets were returned to service by the end of September 2004. Fourth-quarter segment profit is also expected to be impacted.

During third-quarter 2004, we reevaluated the methodology for recognition of revenues related to our Devils Tower facility placed into service in second-quarter 2004. Based on this review, we corrected our revenue recognition methodology to apply the units of production method which recognizes revenues as volumes are delivered over the life of the reserves as opposed to recognizing revenue on the fixed fee received over a defined term. As a result of this correction in methodology, we reduced third-quarter revenues by $16.5 million related to revenues previously recognized in the second quarter of 2004. We have concluded that the effect of the change from the previous accounting treatment is not material to the second or third quarter of 2004. Cash flows are not impacted by this correction.

We requested a waiver from the FERC regarding compliance with FERC Order 2004 for the operation of Discovery Gas Transmission and Black Marlin assets. In July, the FERC granted a partial waiver allowing our Midstream segment to continue to manage these assets without subjecting Midstream to energy affiliate status under FERC Order 2004 by virtue of its operation of those interstate transmission assets. The partial waiver was subject to the remaining requirements of the FERC order. After evaluating the details of the partial waiver, we determined Midstream can continue to manage these assets and comply with FERC Order 2004 without subjecting Midstream to energy affiliate status under FERC Order 2004. We also determined that it was necessary to transfer management of our equity investment in the Aux Sable processing plant to our Power segment in order to avoid classification as an energy affiliate under FERC Order 2004. This transfer was effective September 21, 2004. Our results have been restated to reflect this transfer.

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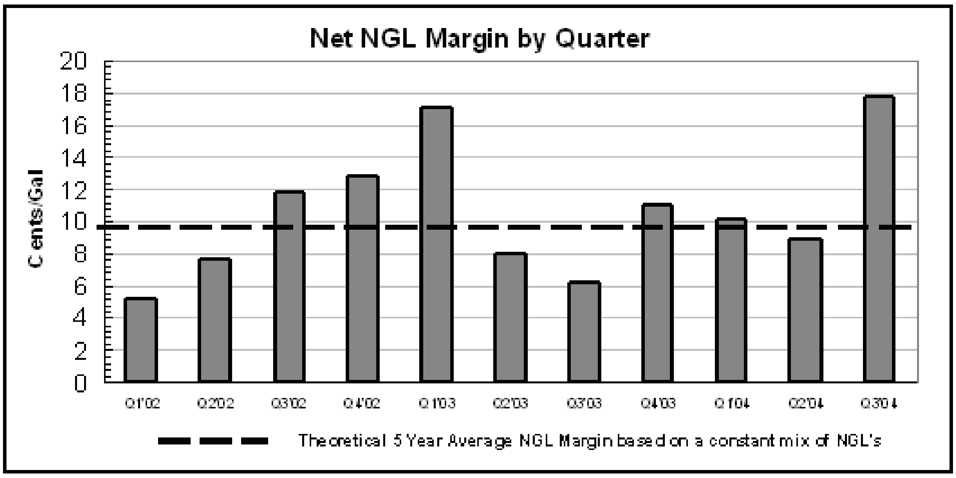
Outlook for the remainder of 2004

The following factors could impact our business in the remaining quarter of 2004 and beyond:

- Our domestic gas processing margins benefited from increased crude oil prices in the first nine months of 2004. As indicated in the graph below, our third quarter margins far exceeded the historical five-year annual average. Current market indicators suggest fourth quarter margins will again exceed the five-year average. However, since natural gas and crude oil markets are highly volatile, our processing margins in the first nine months of 2004 are not necessarily indicative of levels expected for the remainder of 2004 and beyond.



- Continued growth in the deepwater areas of the Gulf of Mexico is expected 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 overall exposure to commodity price risks.

- Beginning in the second quarter of 2003, our Gulf Coast gas processing plants earned additional fee revenues from short-term processing agreements contracted in response to gas merchantability orders from pipeline operators requiring producers' gas to be processed to achieve pipeline quality standards. These contracts could be terminated as a result of a shift in regulatory policy or a sustained, long-term period of favorable gas processing margins. The termination of these short-term contracts could result in lower Gulf Coast processing revenues.

Period-over-period results

As discussed above, Midstream's results of operations have been restated to reflect the transfer of the Aux Sable gas processing plant investment to our Power segment in response to FERC Order 2004. Effective June 1, 2004, and due in part to our response to FERC Order 2004, management and decision-making control of certain regulated gas gathering assets was transferred from our Midstream segment to our Gas Pipeline segment. Consequently, the results of operations were similarly reclassified. During second-quarter 2004, we also reclassified the operations of the Canadian Straddle Plants to discontinued operations. The Canadian liquids system and Gulf Liquids continue to be classified as discontinued operations. All periods presented reflect these classifications.

	Three months ended September 30,		**Nine months ended September 30,**	
	2004	**2003**	**2004**	**2003**
	(Millions)		**(Millions)**	
Segment revenues	$746.4	$701.8	$2,004.2	$2,069.4
Segment profit (loss)				
Domestic Gathering & Processing	$ 75.5	58.1	231.0	218.9
Venezuela	19.7	23.5	60.6	57.0
Other	9.8	(4.3)	20.5	(28.6)
Total	$105.0	$ 77.3	$ 312.1	$ 247.3

Management's Discussion and Analysis (Continued)

Three months ended September 30, 2004 vs. three months ended September 30, 2003

The $44.6 million increase in Midstream's revenues is primarily the result of favorable gas processing and olefins production economics largely offset by lower trading revenues resulting from the fourth-quarter 2003 sale of our wholesale propane business. Revenues associated with production of natural gas liquids (NGLs) increased $144 million, of which $71 million is due to higher volumes and $73 million is due to higher NGL prices. Olefins revenues increased $51 million as a result of both higher market prices and higher volumes. These increased product sales were partially offset by a $21 million decline in fee revenues largely due to the accounting correction related to Devils Tower revenue recognition discussed previously and the loss of revenues caused by Hurricane Ivan. Other factors affecting total revenues, but unrelated to our current business drivers, include significantly lower trading revenues resulting from the fourth-quarter 2003 sale of our wholesale propane business, partially offset by a $138 million increase as the result of marketing NGLs on behalf of our customers. Before 2004, our purchases of customers' NGLs were netted within revenues. In 2004, these purchases of customers' NGLs are included in costs and operating expenses which substantially offsets the change in revenues.

Costs and operating expenses increased $5 million as a result of $93 million in higher costs related to the production of NGLs and $34 million in higher costs related to the production of olefins products. These increases are due to the higher product sales volumes noted above as well as higher natural gas and olefins feedstock prices. Similar to the impact to revenues, total costs and operating expenses increased $138 million due to the marketing of NGLs on behalf of customers. These higher costs and operating expenses are largely offset by lower trading cost of sales due to the sale of our wholesale propane business noted above.

The $27.7 million increase in Midstream segment profit for the third quarter of 2004 is primarily due to higher NGL and olefins margins, partially offset by the Devils Tower revenue correction, the impact of Hurricane Ivan, higher operating expenses, and the absence in 2004 of a gain related to the sale of an equity investment in the third quarter of 2003. A more detailed analysis of segment profit of Midstream's various operations is presented below.

Domestic Gathering & Processing: The $17.4 million increase in domestic gathering and processing segment profit includes an increase of $28.9 million in the West region's segment profit partially offset by an $11.5 million decrease in the Gulf Coast region.

The $28.9 million increase in our West region's segment profit is primarily due to improved net NGL margins. Following are certain significant components of the increase:

- Our West region's net NGL margins in the third quarter of 2004 increased $37 million as a result of 40 percent higher NGL sales prices partially offset by a 12 percent increase in prices for natural gas purchases. Of the $37 million increase in net NGL margins, $33 million is due to higher per unit margins while $4 million is the result of higher volumes. Our net NGL margin per gallon increased 284 percent, from 4.7 cents per gallon in the third quarter of 2003 to 18 cents per gallon in the same quarter of 2004. In addition, our West plants operated at full NGL recovery mode throughout the third quarter of 2004, resulting in a 48 percent increase in NGL production volumes.

- Also offsetting the favorable NGL margins is the $2.2 million difference between a $6.4 million write-down of an idle treating facility reflected in the third quarter 2004 and a $4.2 million write-down of facilities in the third quarter of 2003.

The $11.5 million decrease in our Gulf Coast region's segment profit is due to lower deepwater segment profit, primarily related to the Devils Tower revenue correction, partially offset by higher net NGL margins. Following are certain significant components of the decline:

- Segment profit from our deepwater assets decreased $21 million primarily due to the revenue recognition correction related to our Devils Tower facility placed into service in second-quarter 2004. Based on the change to the units of production revenue recognition methodology discussed above, we recorded an adjustment to reduce revenues by $16.5 million. As a result of this correction, as well as a $3 million negative impact from Hurricane Ivan, our Devils Tower assets reflected a $16 million operating loss in the third quarter. Additionally, fee revenues from our other deepwater facilities declined $4 million due to lower gas production volumes, partially offset by higher transportation volumes related to our new Alpine oil pipeline.

- Net NGL margins at our Gulf Coast gas processing plants increased $15 million, of which $8 million is due to higher NGL prices and $7 million is due to higher production volumes. NGL production volumes increased 105 percent in the third quarter of 2004 compared to the third quarter of 2003, while NGL prices increased 36 percent over the same period.

Venezuela: The $3.8 million decrease in segment profit related to our Venezuelan assets is primarily due to slightly lower revenues and higher operating expenses at our PIGAP gas compression facility.

Other: The $14.1 million improvement in our other Midstream businesses is largely due to improved olefins fractionation margins and higher NGL marketing margins, partially offset by the absence of the third quarter 2003 gain on sale of a partnership investment. The overall improvement in our other businesses is discussed below:

- Segment profit for the olefins businesses increased $17 million primarily as a result of higher olefins fractionation margins at our Gulf Coast and Canadian facilities reflecting the continued strength of the ethylene market throughout 2004. As a result of lower ethylene inventories and higher demand, average prices for olefins products in the third quarter of 2004 were 36 percent higher than those in the third quarter of 2003. This higher demand also resulted in 23 percent higher sales volumes. In addition, the fractionation margin benefited from a new higher fixed margin contract which began in 2004.

- Segment profit for our NGL trading, fractionation, and storage business increased $6 million primarily due to the $3.5 million in higher marketing margins generated as a result of increasing NGL market prices while our production barrels are being transported to market. Additionally, selling, general and administrative expense declined as a result of the fourth-quarter 2003 sale of our wholesale propane business.

- Segment profit related to our investments in partially owned domestic assets accounted for using the equity method declined $9.2 million largely due to the absence of an $11 million gain on the third quarter 2003 sale of our investment in the West Texas Pipeline.

Nine months ended September 30, 2004 vs. nine months ended September 30, 2003

The $65.2 million decrease in Midstream's revenues is primarily the result of lower trading revenues largely due to the fourth-quarter 2003 sale of our wholesale propane business. This decline was largely offset by higher revenues from all of Midstream's current businesses. Revenues associated with production of NGLs increased $264 million, of which $160 million is due to higher volumes and $104 million is due to higher NGL prices. Olefins revenues increased $163 million as a result of both higher market prices and higher volumes. In addition, revenues increased $266 million as the result of marketing NGLs on behalf of our customers. Before 2004, our purchases of customers' NGLs were netted within revenues. In 2004, these purchases of customers' NGLs are included in costs and operating expenses, which offsets the change in revenue.

Costs and operating expenses decreased $116 million primarily as a result of lower trading costs largely due to the sale of our wholesale propane business. This decline was largely offset by $217 million in higher costs related to the production of NGLs and $130 million in higher costs related to the production of olefins products. These costs increased as a result of both the higher production volumes noted above and the higher prices for natural gas and olefins feedstock. Similar to the impact to revenues, total costs and operating expenses increased $266 million due to the marketing of NGLs on behalf of customers.

The $64.8 million increase in Midstream segment profit for the first nine months of 2004 is primarily due to higher NGL and olefins production margins and lower general and administrative expenses. These increases are partially offset by lower fee revenues related to gathering and processing activities and higher operating expenses. A more detailed analysis of segment profit of Midstream's various operation is presented below.

Domestic Gathering & Processing: The $12.1 million increase in domestic gathering and processing segment profit includes a $9 million increase in the West region and a $3.1 million increase in the Gulf Coast region.

The $9 million increase in our West region's segment profit reflects higher NGL margins offset by lower fee revenues and higher operating expenses. The significant components of this increase are explained below:

- Our West region's net NGL margins for the first nine months of 2004 increased $28 million compared to the same period in 2003. With crude prices rising to record highs, average NGL prices outpaced increases in the price of natural gas purchased to replace the heating content of NGLs. The higher per unit margins resulted in a $15 million increase in overall NGL margins. As a result of the higher spread between the prices of NGLs and natural gas, our West plants operated at near capacity and produced 20 percent higher volumes which resulted in a $13 million increase in NGL margins.

- Fee revenue related to gathering and processing activities declined $4 million due to lower volumes and rates, partially offset by higher other fees primarily due to increased dehydration fees at our Opal facility. In addition, higher natural gas prices resulted in a $3 million unfavorable variance related to gathering fuel purchases.

- Also offsetting the favorable NGL margins is the $2.2 million unfavorable net difference between a $6.4 million write-down of an idle treating facility reflected in the third quarter of 2004 and a $4.2 million write-down of the same facility in the third quarter of 2003.

- Maintenance expenses increased $8 million primarily due to additional scheduled maintenance projects in the San Juan and Wyoming areas.

The $3.1 million increase in our Gulf Coast region's segment profit is due to higher NGL margins partially offset by lower deepwater segment profit and lower gathering and other fee revenues. The significant components of the net increase include the following:

- Net NGL margins at our Gulf Coast gas processing plants increased $18 million due to a 122 percent increase in NGL production volumes partially offset by slightly lower per unit margins. The significantly higher NGL volumes are largely the result of recently completed production handling infrastructure flowing additional deepwater gas production. The impact of higher volumes is partially offset by slightly lower per unit margins caused by higher average natural gas prices compared to NGL prices in 2004.

- Segment profit from our deepwater assets declined $14 million largely due to $9 million in lower gathering and other production handling fees as a result of lower gas production volumes. Also contributing to lower deepwater segment profit is a $6 million operating loss related to assets placed into service in the first quarter of 2004. Hurricane Ivan contributed to the overall decline in deepwater segment profit by approximately $5 million due to lower revenues and higher repair expenses.

Venezuela: The $3.6 million increase in segment profit for our Venezuelan assets is primarily due to the absence of a fire at the El Furrial facility that reduced revenues by $10 million in the first quarter of 2003. The effect of the El Furrial fire is partially offset by $3 million lower operating results at our PIGAP gas compression facility, and $1 million in lower equity earnings from our investment in the ACCROVEN partnership.

Other: As a result of improved olefins fractionation margins, higher NGL marketing margins, and selling, general and administrative reductions, results from our NGL trading, fractionation, and storage business; olefins businesses, and partnership investments increased $49.1 million. The overall improvement in our other businesses is discussed below:

- Segment profit for our NGL trading, fractionation, and storage business increased $11 million primarily due to $9 million in lower overhead and operating costs resulting from the fourth-quarter 2003 sale of our wholesale propane business.

- Segment profit for the olefins businesses increased $41 million. Domestic olefins fractionation margins improved $21 million reflecting the significant strengthening of the ethylene market in 2004, reflective of lower ethylene inventories and higher demand for olefins products. The olefins cracking margin benefited from increased spot sales and the new higher fixed margin contract. Segment profit from our Canadian olefins business increased $19 million largely due to $12 million in higher olefins fractionation margins which also benefited from the improved olefins markets. Currency translation adjustments were $4 million favorable as a result of a strengthening Canadian dollar.

- Our earnings from partially owned domestic assets accounted for using the equity method decreased $2 million largely due to the absence of items impacting earnings of partnerships in 2003. This 2003 activity includes $13 million in charges associated with accounting adjustments recorded at the Discovery partnership, a $5 million gain on the sale of our investment in Rio Grande Pipeline partnership, a $11 million gain on the sale of our investment in the West Texas LPG Pipeline L.P. partnership, and the absence of approximately $4 million in earnings generated from investments that were sold after the second quarter of 2003. In addition, excluding the accounting adjustments discussed above, equity earnings from Discovery and Baton Rouge Fractionator partnerships increased $2 million in 2004.

Other

	Three months ended September 30,		Nine months ended September 30,	
	2004	2003	2004	2003
	(Millions)		(Millions)	
Segment revenues	$ 6.7	$ 11.0	$ 26.3	$ 59.1
Segment profit (loss)	$ 2.4	$ 4.1	$ (20.6)	$ (42.8)

Other segment revenues for the nine months ended September 30, 2003 includes approximately $22 million of revenues related to certain butane blending assets, which were sold during third-quarter 2003.

Other segment loss for the nine months ended September 30, 2004 includes a $10.8 million impairment and $6.5 million net unreimbursed advisory fees, both related to our investment in Longhorn. The impairment charge reflects 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. The project incurred cost overruns in preparation for commissioning, including higher priced line fill costs. The net unreimbursed advisory fees relate 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, there was no gain or loss on this transaction.

Other segment loss for the nine months ended September 30, 2003 includes an impairment of $42.4 million relating to the investment in equity and debt securities of Longhorn.

Fair value of trading derivatives

The chart below reflects the fair value of derivatives held for trading purposes as of September 30, 2004. We have presented the fair value of assets and liabilities by the period in which we expect them to be realized.

Assets (Liabilities)				
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)	Total Fair Value
		(Millions)		
$ (13)	$ (4)	$ (11)	$ —	$ (28)

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 Power's long-term structured contract position and the activities of our other segments on an economic basis. As of September 30, 2004, the fair value of these non-trading derivative contracts was a net asset of $272 million. Certain of these economic hedges have not been designated as or do not qualify as SFAS No. 133 hedges. As such, changes in the fair value of these derivative contracts are reflected in earnings. We also hold certain derivative contracts, which do qualify as SFAS No. 133 cash flow hedges, which primarily hedge Exploration & Production's forecasted natural gas sales.

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 that the contract is subject to, and 4) the terms of each individual contract.

Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We continually assess this risk. We have credit protection within various agreements to call on additional collateral support if necessary. At September 30, 2004, we held collateral support of $468 million.

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We also enter into netting agreements to mitigate counterparty performance and credit risk. During third-quarter 2004, we did not incur any significant losses due to recent counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts as of September 30, 2004 is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 558.7	$ 678.5
Energy marketers and traders	2,514.5	5,102.0
Financial institutions	1,916.1	1,916.1
Other	41.5	43.1
	$ 5,030.8	7,739.7
Credit reserves		(31.8)
Gross credit exposure from derivatives(b)		$ 7,707.9

We assess our credit exposure on a net basis. The net credit exposure from our derivatives as of September 30, 2004 is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 136.9	$ 149.2
Energy marketers and traders	470.2	704.0
Financial institutions	217.2	217.2
Other	1.2	2.0
	$ 825.5	$ 1,072.4
Credit reserves		(31.8)
Net credit exposure from derivatives(b)		$ 1,040.6

(a) We determine investment grade primarily using publicly available credit ratings. We included counterparties with a minimum Standard & Poor's rating of BBB- or Moody's Investors Service rating of Baa3 in investment grade. We also classify counterparties that have provided sufficient collateral, such as cash, standby letters of credit, adequate parent company guarantees, and property interests, as investment grade.

(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 in the event of assignment or substitution of a new obligation for the existing one.

Financial condition and liquidity

Liquidity

Overview

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, we successfully executed certain critical components of our plan to address significant liquidity challenges during 2003. Key execution steps for 2004 and beyond, and our progress to date, include the following:

1) Completion of planned asset sales, which we estimated would generate proceeds of approximately $800 million in 2004.

   - On March 31, 2004, we completed the sale of our Alaska refinery and related assets for approximately $304 million.

   - On July 28, 2004, we completed the sale of three straddle plants in western Canada for approximately $544 million.

2) Additional reduction of our selling, general and administrative costs.

   - On June 1, 2004, we announced an agreement with IBM Business Consulting Services (IBM) to aid us in transforming and managing certain areas of our accounting, finance and human resources processes. In addition, IBM will manage key aspects of our information technology, including enterprise wide infrastructure and application development. The 7 1/2 year agreement began July 1, 2004 and is expected to reduce costs in these areas while maintaining a high quality of service.

3) The replacement of our cash-collateralized letter of credit and revolver facility with facilities that do not encumber cash.

   - In April 2004, we entered into two unsecured bank revolving credit facilities totaling $500 million. These facilities provide for both borrowings and letters of credit, but are used primarily for issuing letters of credit. Use of these new facilities released approximately $500 million of restricted cash, restricted investments and margin deposits in the second quarter.

   - On May 3, 2004, we entered into a new three-year, $1 billion secured revolving credit facility which is available for borrowings and letters of credit. In August 2004, we expanded the credit facility by an additional $275 million. Northwest and Transco each have access to $400 million under the facility, which is secured by certain Midstream assets and a guarantee from WGP (see Note 12 of Notes to the Consolidated Financial Statements).

4) Efforts to exit from the Power business.

   - In September 2004, our Board of Directors approved the decision to retain Power and end our efforts to exit that business. Several factors affected our decision to retain the business, including:

     - the cash flow expected to be generated by the business (Power has contracts in place expected to generate cash in amounts that substantially cover its obligations through 2010);

     - the negative effect of depressed wholesale power markets on the marketability of the Power segment; and

     - our progress over the last two years in reducing the risk of and increasing the certainty of cash flow from long-term power contracts.

   We will continue our current program of managing this business to minimize financial risk, generate cash and manage existing contractual commitments.

Additionally, we have continued to reduce debt, eliminating over $3 billion for the nine months ended September 30, 2004 through scheduled maturities and early redemptions.

- On March 15, 2004, we retired the remaining $679 million outstanding balance of the 9.25 percent senior unsecured notes due March 15, 2004.
- In May 2004, we repurchased on the open market approximately $255 million of various notes with maturity dates ranging from 2006 to 2011.
- In June 2004, we retired approximately $1.17 billion of notes and debentures through a May 2004 tender offer.
- In September 2004, we retired approximately $793 million of notes through an August 2004 tender offer.
- During the fourth quarter, we completed an offer to exchange up to 43.9 million FELINE PACS units for one share of our common stock plus $1.47 in cash for each unit. The exchange offer was designed to reduce overall debt by up to $1.1 billion and to reduce interest expense. At the October 18, 2004, expiration date of the exchange offer, approximately 33.1 million units, or $827 million of the notes, had been tendered and accepted for exchange.

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 September 30, 2004, we have the following sources of liquidity from cash and cash equivalents:

- Cash-equivalent investments at the corporate level of $808 million as compared to $2.2 billion at December 31, 2003.
- Cash and cash-equivalent investments of various international and domestic entities of $169 million, as compared to $91 million at December 31, 2003.

At December 31, 2003, we had capacity of $447 million available under the $800 million revolving and letter of credit facility. This facility was terminated on May 3, 2004. At September 30, 2004, we have capacity of $7 million available under the two unsecured revolving credit facilities totaling $500 million and capacity of $837 million available under our $1.275 billion secured revolving 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. However, the ability to utilize this shelf registration for debt securities is restricted by certain covenants of our debt agreements.

In addition, our wholly owned subsidiaries Northwest and Transco have outstanding registration statements filed with the Securities and Exchange Commission. As of September 30, 2004, approximately $350 million of shelf availability remains under these registration statements. However, the ability to utilize these registration statements is restricted by certain covenants of our debt agreements. Interest rates, market conditions, and industry conditions will affect amounts raised, if any, in the capital markets.

During the first nine months of 2004, we satisfied liquidity needs with:

- $304 million in cash generated from the sale of the Alaska refinery and related assets;
- approximately $544 million in cash generated from the sale of the Canadian straddle plants; and
- approximately $1.1 billion in cash generated from operating activities of continuing operations, including the release of approximately $500 million of restricted cash, restricted investments and margin deposits previously used to collateralize certain credit facilities.

Credit ratings

As part of executing the business plan announced in February 2003, we established a goal of returning to investment grade status. While reduction of debt is viewed as a key contributor towards this goal, certain of the key credit rating agencies have imputed the financial commitments associated with our long-term tolling agreements within the Power business as debt. Due to our decision to remain in the Power business, obtaining an investment grade rating could be delayed. See Note 1 of Notes to Consolidated Financial Statements for a further discussion of the Power business.

On July 30, 2004, Standard & Poor’s raised our debt ratings outlook to stable from negative citing our debt reduction efforts. If we continue to reduce debt in line with forecasts, our rating could improve over the three-year horizon of the outlook. An improved rating could result in lower borrowing costs. However, if financial ratios fall considerably below expectations, the outlook and the rating could decline.

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

As discussed in *Overview*, in April 2004, we entered into two unsecured bank revolving credit facilities totaling $500 million. We were able to obtain the unsecured credit facilities because the funding bank syndicated its associated credit risk into the institutional investor market via a Rule 144A offering, which allows for the sale of certain restricted securities only to qualified institutional buyers. Upon the occurrence of certain credit events, letters of credit outstanding under the agreement become cash collateralized, creating a borrowing under the facilities. Concurrently, the bank can deliver the facilities to the institutional investors, whereby the investors replace the bank as lender under the facilities.

To facilitate the syndication of the facilities, the bank established trusts funded by the institutional investors. The assets of the trusts serve as collateral to reimburse the bank for our borrowings in the event the facilities are delivered to the investors. We have no asset securitization or collateral requirements under the new facilities. During the second quarter, use of these new facilities released approximately $500 million of restricted cash, restricted investments and margin deposits (see Note 12 of Notes to the Consolidated Financial Statements).

Operating activities

For the nine months ended September 30, 2004, we recorded approximately $55.5 million in Provision for loss on investments, property and other assets consisting primarily of a $15.7 million impairment of a cost-based investment in the Indonesian toll road, 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’s system.

For the nine months ended September 30, 2003, we recorded approximately $133.5 million in Provision for loss on investments, property and other assets consisting primarily of a $42.4 million impairment of our investment in Longhorn, a $25.5 million write-off of software development costs at Northwest, a $14.1 million impairment of our investment in Aux Sable, a $13.5 million impairment of an investment in a company holding phosphate reserves and a $13.2 million impairment of Algar Telecom S.A.

The net gain on disposition of assets in 2003 primarily consists of the gains on the sales of natural gas properties in the second quarter of 2003.

In 2003, we recorded an accrual for fixed rate interest included in the RMT Note on the Consolidated Statement of Cash Flows representing the quarterly non-cash reclassification of the deferred fixed rate interest from an accrued liability to the RMT Note. The Amortization of deferred set-up fee and fixed rate interest on the RMT Note relates to amounts recognized in the Consolidated Statement of Operations as interest expense, but which were not payable until maturity. The RMT Note was repaid in May 2003.

The increase in funds from Restricted cash is due to the release of cash held as collateral for various surety bonds.

Financing activities

On March 15, 2004, we retired the remaining $679 million outstanding balance of the 9.25 percent senior unsecured notes due March 15, 2004. The amount represented the outstanding balance of the notes remaining after the fourth-quarter 2003 tender which retired $721 million of the original $1.4 billion balance.

In May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of a specified series of our outstanding notes and debentures. We accepted approximately $1.17 billion of notes and debentures for purchase. We also repurchased on the open market approximately $255 million of various notes with maturity dates ranging from 2006 to 2011. In August 2004, we made cash tender offers and consent solicitations for all $800 million of our 8.625 percent senior notes due 2010. We accepted approximately $793 million of notes for purchase. In conjunction with the tendered notes, related consents, and the debt repurchase, we paid premiums of approximately $214 million. The premiums, as well as related fees and expenses, together totaling $252.4 million, are presented in Early debt retirement costs on the Consolidated Statement of Cash Flows.

In June 2004, we made a payment of approximately $109 million for accrued interest, short-term payables, and long-term debt to repurchase 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. In July 2004, we received payment of approximately $104 million from the California Power Exchange which is reported in Changes in accounts and notes receivable on the Consolidated Statement of Cash Flows.

For a discussion of other borrowings and repayments in 2004, see Note 12 of Notes to Consolidated Financial Statements.

Dividends paid on common stock are currently $.01 per common share on a quarterly basis and totaled $15.6 million for the nine months ended September 30, 2004. One of the covenants under the $500 million revolving credit facilities currently limits our quarterly common stock dividends to not more than $.05 per common share. This restriction will be removed if certain requirements in the covenants are met.

Investing activities

During September 2004, we received a $67.9 million payment from WilTel, which included payment in full on the balance of our short-term note receivable of $54.6 million and a principal payment on the long-term note receivable in the amount of $13.3 million. The remaining $60.8 million balance of the long-term note receivable is to be paid over the next six years. This activity is included in Payments received on notes receivable from WilTel on the Consolidated Statement of Cash Flows.

During the first four months of 2004, we purchased $471.8 million of restricted investments comprised of U.S. Treasury notes and received proceeds on maturity of $851.4 million of such investments on their scheduled maturity date. We made these purchases to satisfy the 105 percent cash collateralization requirement in the $800 million revolving credit facility. This facility was terminated on May 3, 2004, after we obtained the $1 billion secured revolving credit facility (see Note 12 of Notes to Consolidated Financial Statements).

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 preferred equity interests in Longhorn. The $58 million received is included in Proceeds from dispositions of investments and other assets.

The following sales in the first nine months of 2004 and 2003 provided significant proceeds and may include various adjustments subsequent to the actual date of sale.

In 2004:

- approximately $544 million in net proceeds related to the sale of our Canadian straddle plants; and
- $305 million related to the sale of Alaska refinery, retail and pipeline and related assets.

In 2003:

- $799 million related to the sale of Texas Gas Transmission Corporation;
- $431 million (net of cash held by Williams Energy Partners) related to the sale of our general partnership interest and limited partner investment in Williams Energy Partners;
- $452 million related to the sale of the Midsouth refinery;
- $464 million related to certain natural gas exploration and production properties in Kansas, Colorado, New Mexico and Utah;
- $192 million related to the sale of certain natural gas liquids assets in Redwater, Alberta;
- $188 million related to the sale of the Williams travel centers;
- $59 million related to the sale of our equity interest in Williams Bio-Energy L.L.C.; and
- $40 million related to the sale of the Worthington facility.

Contractual obligations

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, we had certain contractual obligations at December 31, 2003, with various maturity dates, related to the following:

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

During the first nine months of 2004, the amount of our contractual obligations changed significantly due to the following:

- We retired more than $2.2 billion of long-term debt through tender offers and open market purchases (see Note 12 of Notes to Consolidated Financial Statements).
- On March 15, 2004, we retired the remaining $679 million outstanding balance of the 9.25 percent senior unsecured notes due March 15, 2004.
- On March 31, 2004, as part of the sale of the Alaska refinery, we terminated a $385 million crude purchase contract with the state of Alaska.
- On May 27, 2004, we were released from certain historical indemnities, primarily related to environmental remediation, for an agreement to pay $117.5 million (see Note 13 of Notes to Consolidated Financial Statements). On July 1, 2004, we made the first payment of $35 million. The outstanding amount will be paid in three installments of $27.5 million, $20 million, and $35 million on July 1, 2005, 2006, and 2007, respectively.
- Over the course of the first nine months of 2004, Power's physical and financial derivative obligations decreased by approximately $1.6 billion. The decrease is due to the realization of contracts during the first nine months of 2004, as well as normal trading and market activity.

Outlook for the remainder of 2004

We estimate capital and investment expenditures will total approximately $775 million to $875 million for the year ended 2004, or approximately $236 million to $336 million for the fourth-quarter 2004. During the remainder of 2004, we expect to fund capital and investment expenditures, debt payments and working-capital requirements through cash and cash equivalent investments on hand and cash generated from operations. We expect to generate $1.25 billion to $1.45 billion in cash flow from continuing operations for the year ended 2004, or approximately $184 million to $384 million in the fourth quarter of 2004.

To manage our operations and meet unforeseen or extraordinary calls on cash, we expect to maintain liquidity levels of at least $1 billion. Through debt tenders, open market repurchases and scheduled maturities, we have reduced our debt to $8.9 billion at September 30, 2004, a reduction of over $3 billion for the year-to-date. While our access to the capital markets continues to improve, our two unsecured revolving credit facilities have covenants that restrict our ability to issue new debt, with minimal exceptions, until a certain fixed charge coverage ratio is achieved. We expect to satisfy this requirement by the end of 2005. In addition, our secured revolving credit facility has a covenant restricting our ability to issue new debt if, after giving effect to the issuance, we were to fail to meet the associated consolidated debt to consolidated net worth ratio.

On November 1, 2004, Winterthur remitted approximately $85 million to us in the settlement of certain disputes regarding obligations under construction contracts (see Note 6 of Notes to Consolidated Financial Statements). As a result of the payment, we will recognize pre-tax income of approximately $95 to $100 million within Income from discontinued operations in the fourth quarter.

Item 3

Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our interest rate risk exposure associated with the debt portfolio was impacted primarily by debt early retirements and payments during the first nine months of 2004. On March 15, 2004, we retired the remaining $679 million balance of the 9.25 percent senior unsecured notes due March 15, 2004. In May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of a specified series of our outstanding notes and debentures. As of the June 8, 2004, tender offer expiration date, we had accepted for purchase tenders of notes and debentures with an aggregate principle amount of approximately $1.17 billion. In May 2004, we also repurchased approximately $255 million of various notes with maturity dates ranging from 2006 to 2011. In August 2004, we made a cash tender offer and consent solicitation for any and all $800 million of our 8.625 percent senior notes due 2010. We accepted $793 million of notes for purchase (see Note 12 of the Notes to Consolidated Financial Statements).

On February 25, 2004, our Exploration & Production segment amended its $500 million secured note facility, reducing the floating interest rate from the LIBOR plus 3.75 percent to LIBOR plus 2.5 percent (see Note 12 of the Notes to Consolidated Financial Statements).

On September 17, 2004, we initiated an offer to exchange up to 43.9 million FELINE PACS units for one share of our common stock plus $1.47 in cash for each unit (see Note 12 of the Notes to Consolidated Financial Statements). The offer expired on October 18, 2004. The exchange offer reduced our 6.5 percent notes, due 2007, by approximately $827 million.

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. 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. The value-at-risk model 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 value-at-risk model uses historical simulations to estimate hypothetical movements in future market prices. In these simulations, we assume normal market conditions and historical market prices. In applying the value-at-risk methodology, we do not 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 No. 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. The value at risk for contracts held for trading purposes was $1 million and $5 million at September 30, 2004 and December 31, 2003, respectively.

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 • Natural gas liquids purchases • Natural gas liquids sales
Power	• Natural gas purchases • Electricity purchases • Electricity sales

The value at risk for contracts held for non-trading purposes was $18.5 million at September 30, 2004 and $18 million at December 31, 2003. Certain of the contracts held for non-trading purposes were accounted for as cash flow hedges under SFAS No. 133. We did 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.

Foreign Currency Risk

The sale of our Canadian straddle plants in July 2004 decreased our exposure to foreign currency risk. The portion of our consolidated net assets held by foreign operations whose functional currency is the local currency decreased from approximately 15 percent at December 31, 2003, to approximately 8 percent at September 30, 2004. The change in stockholders equity caused by a 20 percent change in the value of the respective functional currencies against the U.S. Dollar decreased from approximately $125 million at December 31, 2003 to approximately $65 million at September 30, 2004.

Item 4

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 its 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.

As stated in our year-end and first and second quarter reports we have identified certain portions of our account reconciliation process whereby the controls and policies are in the process of being enhanced across all business segments. As of the third quarter certain enhancements have been implemented with continued review and evaluation of effectiveness occurring in the fourth quarter.

Effective July 1, 2004, the company entered into an outsourcing agreement with IBM which will improve our ability to adjust support operations as business conditions dictate while maintaining a high quality of service. The services being rendered by IBM include certain aspects of the company's accounting, human resources and information technology activities. The more significant of these include payroll, accounts payable, property, general ledger and related accounting, benefits, compensation, infrastructure and applications. As a result of the outsourcing substantially all of the company's employees in the outsourced functions were initially hired by IBM and continued performing the same functions during the third quarter. Contractually, IBM is required to develop and implement internal controls and has agreed to work with the company to implement compliance measures to satisfy the Sarbanes-Oxley Act of 2002. IBM has agreed to make minimal changes to processes and systems through year end 2004.

Notwithstanding the above, management concludes that its current controls are effective at a reasonable assurance level. In addition, there has been no material change, other than the outsourcing described above, in our Internal Controls that occurred during the registrant's third fiscal quarter.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information called for by this item is provided in Note 13 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 and Issues Purchases of Equity Securities

Effective as of August 17, 2004, we executed a Tenth Supplemental Indenture with JPMorgan Chase Bank, as trustee, regarding the 8.625 percent Senior Notes due 2010 issued under a Ninth Supplemental Indenture dated as of June 10, 2003, which supplemented a base Indenture dated as of November 10, 1997. The Tenth Supplemental Indenture was entered into as part of a tender offer pursuant to which substantially all of the 8.625 percent Senior Notes were repurchased. For those noteholders who elected not to tender their notes, the Tenth Supplemental Indenture eliminated substantially all of the restrictive covenants and certain events of default and related provisions in the Ninth Supplemental Indenture that, among other things, limited our ability to pay quarterly dividends to no greater than $0.02 per common share.

Item 6. Exhibits

The exhibits listed below are filed as part of this report:

Exhibit 3.1* — The Williams Companies, Inc. By-laws effective September 15, 2004 (filed as Exhibit 3.1 to Form 8-K filed September 21, 2004).

Exhibit 4.1* — Tenth Supplemental Indenture dated as of August 17, 2004, with respect to the Indenture dated as of November 10, 1997 between The Williams Companies, Inc. and JPMorgan Chase Bank (as successor trustee to Bank One Trust Company, National Association (successor to the First National Bank of Chicago)) (filed as Exhibit 99.2 to Form 8-K filed August 17, 2004).

Exhibit 4.2* — Amended and Restated Rights Agreement dated September 21, 2004 by and between The Williams Companies, Inc. and EquiServe Trust Company, N.A., as Rights Agent (filed as Exhibit 4.1 to Form 8-K filed September 21, 2004).

Exhibit 10.1 — Letter of Credit Commitment Increase Agreement dated August 4, 2004, by and among The Williams Companies, Inc., Citicorp USA in its capacity as Agent under the Credit Agreement dated as of May 3, 2004 among the Borrower, Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, the Agent, the Collateral Agent, the Banks and Issuing Banks party thereto and Citibank, N.A. and Bank of America, N.A.

Exhibit 10.2 — Revolving Credit Commitment Increase Agreement dated August 4, 2004, by and among The Williams Companies, Inc., Citicorp USA, Inc. in its capacity as Agent under the Credit Agreement dated as of May 3, 2004 among the Borrower, Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, the Agent, the Collateral Agent and the Banks and Issuing Banks party thereto, the Issuing Banks and Citicorp USA, Inc.

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.

* Such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

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/ Gary R. Belitz
Gary R. Belitz
Controller (Duly Authorized Officer and Principal Accounting Officer)

November 4, 2004

Exhibit 10.1

LETTER OF CREDIT COMMITMENT INCREASE AGREEMENT

This Letter of Credit Commitment Increase Agreement dated as of August 4, 2004, to be effective as of August 9, 2004 (this "Agreement") is by and among (i) The Williams Companies, Inc., a Delaware corporation ("Borrower"), (ii) Citicorp USA, Inc. in its capacity as Agent under the Credit Agreement dated as of May 3, 2004 (as it may be amended or modified from time to time, the "Credit Agreement", capitalized terms that are defined in the Credit Agreement and not defined herein are used herein as therein defined) among the Borrower, Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, the Agent, the Collateral Agent, the Banks and Issuing Banks party thereto, and (iii) Citibank, N.A. and Bank of America, N.A. ("Increasing Banks").

Preliminary Statements

A. Pursuant to Section 2.19 of the Credit Agreement, the Borrower has the right, subject to the terms and conditions thereof, to agree with an Issuing Bank to increase that Issuing Bank's Letter of Credit Commitment.

B. The Borrower has given notice to the Agent of its intention, pursuant to such Section 2.19 and with the consent of the Increasing Banks, to increase each of the Letter of Credit Commitments of Citibank, N.A. and Bank of America, N.A. from $500,000,000.00 to $637,500,000.00, and the Agent is willing to consent thereto.

Accordingly, the parties hereto agree as follows:

Section 1. Increase of Commitment. Pursuant to Section 2.19 of the Credit Agreement, the Letter of Credit Commitments of each Increasing Bank is hereby increased from $500,000,000.00 to $637,500,000.00.

Section 2. Consent. The Agent and the Borrower hereby consent and agree to the increase in the Letter of Credit Commitment of the Increasing Bank effectuated hereby.

Section 3. Governing Law. This Agreement shall be governed by, and construed in accordance with, the laws of the State of New York.

Section 4. Execution in Counterparts. This Agreement may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed shall be deemed to be an original and all of which taken together shall constitute one and the same agreement.

Section 5. Bank Credit Decision. The Increasing Bank acknowledges that it has, independently and without reliance upon the Agent, the Issuing Banks, the Collateral Agent or any other Bank and based on the financial statements referred to in Section 4.1 of the Credit Agreement and such other documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement and to agree to the various matters set forth herein. The Increasing Bank also acknowledges that it will, independently and without reliance upon the Agent, the Issuing Banks, the Collateral Agent or any other Bank and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Credit Documents.

Section 6. Representations and Warranties of the Borrower. The Borrower represents and warrants as follows:

(a) The execution, delivery and performance by the Borrower of this Agreement are within the Borrower's corporate powers, have been duly authorized by all necessary corporate action of the Borrower, require, in respect of the Borrower, no action by or in respect of, or filing with, any governmental body, agency or official and do not contravene, or constitute a default under, any provision of law or regulation applicable to the Borrower or Regulation U issued by the Federal Reserve Board or the charter or bylaws of the Borrower or any judgment, injunction, order, decree or agreement binding upon the Borrower or result in the creation or imposition of any Lien prohibited by the Credit Agreement.

(b) This Agreement is a legal, valid and binding obligation of the Borrower enforceable against the Borrower in accordance with its terms, except as the enforceability thereof may be limited by the effect of any applicable bankruptcy, insolvency, reorganization, moratorium or similar laws affecting creditors' rights generally and by general principles of equity.

(c) After giving effect to this Agreement and all other Letter of Credit Commitment Increase Agreements, the Borrower will be in compliance with the limitation set forth in clause (i)(2) of the proviso to Section 2.19(e) of the Credit Agreement.

(d) No event has occurred and is continuing which constitutes a Default or an Event of Default.

(e) Attached hereto are resolutions duly adopted by the Board of Directors of the Borrower sufficient to authorize this Agreement, and such resolutions are in full force and effect.

Section 7. Default. Without limiting any other event that may constitute an Event of Default, in the event any representation or warranty set forth herein shall prove to have been incorrect in any material respect when made, such event shall constitute an "Event of Default" under the Credit Agreement.

Section 8. Expenses. The Borrower agrees to pay on demand all reasonable out-of-pocket costs and expenses of the Agent in connection with the preparation, negotiation, execution and delivery of this Agreement, including, without limitation, the reasonable fees and out-of-pocket expenses of external counsel for the Agent with respect thereto.

Section 9. Effectiveness. When, and only when, the Agent shall have received counterparts of, or telecopied signature pages of, this Agreement executed by the Borrower, the Agent and the Increasing Bank, this Agreement shall become effective as of August 9, 2004.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their respective officers thereunto duly authorized, as of the date first above written.

BORROWER:

THE WILLIAMS COMPANIES, INC.

By: /s/ Travis N. Campbell

Name: Travis N. Campbell
Title: Treasurer

AGENT:

CITICORP USA, INC., as Agent

By: /s/ Todd J. Mogil

Name: Todd J. Mogil
Title: Vice President

INCREASING BANKS:

CITIBANK, N.A.

By: /s/ Todd J. Mogil

Name: Todd J. Mogil
Title: Attorney-in-Fact

BANK OF AMERICA, N.A.

By: /s/ Claire M. Liu

Name: Claire M. Liu
Title: Managing Director

Exhibit 10.2

REVOLVING CREDIT COMMITMENT INCREASE AGREEMENT

This Revolving Credit Commitment Increase Agreement dated as of August 4, 2004, to be effective as of August 9, 2004 (this “Agreement”) is by and among (i) The Williams Companies, Inc., a Delaware corporation (“Borrower”), (ii) Citicorp USA, Inc. in its capacity as Agent under the Credit Agreement dated as of May 3, 2004 (as it may be amended or modified from time to time, the “Credit Agreement”, capitalized terms that are defined in the Credit Agreement and not defined herein are used herein as therein defined) among the Borrower, Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, the Agent, the Collateral Agent and the Banks and Issuing Banks party thereto, (iii) the Issuing Banks, and (iv) Citicorp USA, Inc. (“Increasing Bank”).

Preliminary Statements

A. Pursuant to Section 2.19 of the Credit Agreement, the Borrower has the right, subject to the terms and conditions thereof, to agree with a Bank to increase that Bank’s Revolving Credit Commitment for the Borrower.

B. The Borrower has given notice to the Agent of its intention, pursuant to such Section 2.19 and with the consent of the Increasing Bank, to increase the Revolving Credit Commitment of the Increasing Bank for the Borrower from $120,000,000.00 to $395,000,000.00, and the Agent and the Issuing Banks are willing to consent thereto.

Accordingly, the parties hereto agree as follows:

Section 1. Increase of Commitment. Pursuant to Section 2.19 of the Credit Agreement, the Revolving Credit Commitment of the Increasing Bank for the Borrower is hereby increased from $120,000,000.00 to $395,000,000.00

Section 2. New Note. If the Increasing Bank has previously requested a note pursuant to Section 2.10 of the Credit Agreement, the Borrower agrees to promptly execute and deliver to the Increasing Bank a new Note in the amount of its increased Revolving Credit Commitment for the Borrower set forth in Section 1 above (the “New Note”), and the Increasing Bank agrees to return to the Borrower, with reasonable promptness, the Note previously delivered to the Increasing Bank by the Borrower.

Section 3. Consent. The Agent, the Issuing Banks and the Borrower hereby consent and agree to the increase in the Revolving Credit Commitment of the Increasing Bank for the Borrower effectuated hereby.

Section 4. Governing Law. This Agreement shall be governed by, and construed in accordance with, the laws of the State of New York.

Section 5. Execution in Counterparts. This Agreement may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed shall be deemed to be an original and all of which taken together shall constitute one and the same agreement.

Section 6. Bank Credit Decision. The Increasing Bank acknowledges that it has, independently and without reliance upon the Agent, the Issuing Banks, the Collateral Agent or any other Bank and based on the financial statements referred to in Section 4.1 of the Credit Agreement and such other documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement and to agree to the various matters set forth herein. The Increasing Bank also acknowledges that it will, independently and without reliance upon the Agent, the Issuing Banks, the Collateral Agent or any other Bank and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Credit Documents.

Section 7. Representations and Warranties of the Borrower. The Borrower represents and warrants as follows:

(a) The execution, delivery and performance by the Borrower of this Agreement and any New Note are within the Borrower's corporate powers, have been duly authorized by all necessary corporate action of the Borrower, require, in respect of the Borrower, no action by or in respect of, or filing with, any governmental body, agency or official and do not contravene, or constitute a default under, any provision of law or regulation applicable to the Borrower or Regulation U issued by the Federal Reserve Board or the charter or bylaws of the Borrower or any judgment, injunction, order, decree or agreement binding upon the Borrower or result in the creation or imposition of any Lien prohibited by the Credit Agreement.

(b) This Agreement and any New Note are legal, valid and binding obligations of the Borrower enforceable against the Borrower in accordance with their respective terms, except as the enforceability thereof may be limited by the effect of any applicable bankruptcy, insolvency, reorganization, moratorium or similar laws affecting creditors' rights generally and by general principles of equity.

(c) After giving effect to this Agreement and all other Revolving Credit Commitment Increase Agreements, the Borrower will be in compliance with the limitation set forth in clause (i)(2) of the proviso to Section 2.19(a) of the Credit Agreement.

(d) No event has occurred and is continuing which constitutes a Default or an Event of Default.

(e) Attached hereto are resolutions duly adopted by the Board of Directors of the Borrower sufficient to authorize this Agreement and any New Note, and such resolutions are in full force and effect.

Section 8 Default. Without limiting any other event that may constitute an Event of Default, in the event any representation or warranty set forth herein shall prove to have been incorrect in any material respect when made, such event shall constitute an “Event of Default” under the Credit Agreement.

Section 9. Expenses. The Borrower agrees to pay on demand all reasonable out-of-pocket costs and expenses of the Agent in connection with the preparation, negotiation, execution and delivery of this Agreement and any New Note, including, without limitation, the reasonable fees and out-of-pocket expenses of external counsel for the Agent with respect thereto.

Section 10. Effectiveness. When, and only when, the Agent shall have received counterparts of, or telecopied signature pages of, this Agreement executed by the Borrower, the Agent, the Issuing Banks and the Increasing Bank, this Agreement shall become effective as of August 9, 2004.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their respective officers thereunto duly authorized, as of the date first above written.

BORROWER:

THE WILLIAMS COMPANIES, INC.

By: /s/ Travis N. Campbell

Name: Travis N. Campbell
Title: Treasurer

AGENT:

CITICORP USA, INC., as Agent

By: /s/ Todd J. Mogil

Name: Todd J. Mogil
Title: Vice President

ISSUING BANKS:

CITIBANK, N.A.

By: /s/ Todd J. Mogil

Name: Todd J. Mogil
Title: Attorney-in-Fact

BANK OF AMERICA, N.A.

By: /s/ Claire M. Liu

Name: Claire M. Liu
Title: Managing Director

INCREASING BANK:

CITICORP USA, INC.

By: /s/ Todd J. Mogil

Name: Todd J. Mogil
Title: Vice President

Exhibit 12

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

		Nine months ended September 30, 2004
Earnings:		
Income from continuing operations before income taxes	$	39.0
Minority interest in income of consolidated subsidiaries		16.0
Less: Equity earnings		(38.2)
Income from continuing operations before income taxes, minority interest in income of consolidated subsidiaries and equity earnings		16.8
Add:		
Fixed charges:		
Interest accrued, including proportionate share from equity-method investees		665.2
Rental expense representative of interest factor		16.6
Total fixed charges:		681.8
Distributed income of equity investees		43.3
Less:		
Capitalized interest		(5.7)
Total earnings as adjusted	$	736.2
Fixed charges	$	681.8
Ratio of earnings to fixed charges		1.08

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 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)) 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) 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

   c) Disclosed in this report any change in the registrant's internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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.

5. The registrant's other certifying officer 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 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: November 4, 2004

By: /s/ 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 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)) 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) 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

   c) Disclosed in this report any change in the registrant's internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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.

5. The registrant's other certifying officer 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 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: November 4, 2004

By: /s/ Donald R. Chappel

Chief Financial Officer
(Principal Financial 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 September 30, 2004 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
November 4, 2004

/s/ Donald R. Chappel

Donald R. Chappel
Chief Financial Officer
November 4, 2004

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.