

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

FORM 10-Q

Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended March 31, 2006
OR
 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 **001-13643**

ONEOK, Inc.

(Exact name of registrant as specified in its charter)

Oklahoma
(State or other jurisdiction of
incorporation or organization)

73-1520922
(I.R.S. Employer Identification No.)

100 West Fifth Street, Tulsa, OK
(Address of principal executive offices)

74103
(Zip Code)

Registrant's telephone number, including area code **(918) 588-7000**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by checkmark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.
Large accelerated Filer Accelerated Filer Non-accelerated filer

Indicate by checkmark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes No

On April 30, 2006, the Company had 117,395,380 shares of common stock outstanding.

ONEOK, Inc.
QUARTERLY REPORT ON FORM 10-Q

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As used in this Quarterly Report on Form 10-Q, the terms "we", "our" or "us" mean ONEOK, Inc., an Oklahoma corporation, and its predecessors and subsidiaries, unless the context indicates otherwise.

Part I - FINANCIAL INFORMATION

Item 1. Financial Statements

ONEOK, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF INCOME

<i>(Unaudited)</i>	Three Months Ended	
	March 31,	
	2006	2005
<i>(Thousands of dollars, except per share amounts)</i>		
Revenues		
Operating revenues, excluding energy trading revenues	\$ 3,910,952	\$ 2,697,848
Energy trading revenues, net	7,370	9,192
Total Revenues	3,918,322	2,707,040
Cost of sales and fuel	3,343,173	2,336,643
Net Margin	575,149	370,397
Operating Expenses		
Operations and maintenance	167,985	123,502
Depreciation, depletion and amortization	69,426	43,217
General taxes	26,190	17,300
Total Operating Expenses	263,601	184,019
Operating Income	311,548	186,378
Other income	12,555	5,298
Other expense	5,844	782
Interest expense	62,890	26,090
Income before Minority Interest and Income Taxes	255,369	164,804
Minority interest in income of consolidated subsidiaries	45,497	-
Income taxes	80,141	63,026
Income from Continuing Operations	129,731	101,778
Discontinued operations, net of taxes (Note C)		
Income (loss) from operations of discontinued components, net of tax	(239)	5,886
Net Income	\$ 129,492	\$ 107,664
Earnings Per Share of Common Stock (Note O)		
Basic:		
Earnings per share from continuing operations	\$ 1.21	\$ 0.98
Earnings (loss) per share from operations of discontinued components, net of tax	-	0.06
Net earnings per share, basic	\$ 1.21	\$ 1.04
Diluted:		
Earnings per share from continuing operations	\$ 1.17	\$ 0.92
Earnings (loss) per share from operations of discontinued components, net of tax	-	0.05
Net earnings per share, diluted	\$ 1.17	\$ 0.97
Average Shares of Common Stock (Thousands)		
Basic	107,143	103,666
Diluted	110,756	111,001
Dividends Declared Per Share of Common Stock	\$ 0.28	\$ 0.25

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

<i>(Unaudited)</i>	March 31, 2006	December 31, 2005
Assets	<i>(Thousands of dollars)</i>	
Current Assets		
Cash and cash equivalents	\$ 36,800	\$ 7,915
Trade accounts and notes receivable, net	1,501,651	2,202,895
Gas and natural gas liquids in storage	625,029	911,393
Commodity exchanges	39,704	133,159
Energy marketing and risk management assets (Note D)	348,958	765,157
Other current assets	259,054	385,274
Total Current Assets	2,811,196	4,405,793
Property, Plant and Equipment		
Property, plant and equipment	8,648,194	5,575,365
Accumulated depreciation, depletion and amortization	2,718,333	1,581,138
Net Property, Plant and Equipment	5,929,861	3,994,227
Deferred Charges and Other Assets		
Goodwill and intangibles (Note E)	991,264	683,211
Energy marketing and risk management assets (Note D)	113,415	150,026
Investments and other	822,695	716,298
Total Deferred Charges and Other Assets	1,927,374	1,549,535
Assets of Discontinued Component	63,001	63,911
Total Assets	\$ 10,731,432	\$ 10,013,466

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

<i>(Unaudited)</i>	March 31, 2006	December 31, 2005
Liabilities and Shareholders' Equity	<i>(Thousands of dollars)</i>	
Current Liabilities		
Current maturities of long-term debt	\$ 6,551	\$ 6,546
Notes payable	745,000	1,541,500
Accounts payable	1,308,421	1,756,307
Commodity exchanges	122,547	238,176
Energy marketing and risk management liabilities (Note D)	450,555	814,803
Other	444,633	438,009
Total Current Liabilities	3,077,707	4,795,341
Long-term Debt, excluding current maturities	3,104,054	2,024,070
Deferred Credits and Other Liabilities		
Deferred income taxes	604,405	603,835
Energy marketing and risk management liabilities (Note D)	218,138	442,842
Other deferred credits	347,447	350,157
Total Deferred Credits and Other Liabilities	1,169,990	1,396,834
Liabilities of Discontinued Component	1,963	2,464
Commitments and Contingencies (Note K)		
Minority Interests in Consolidated Subsidiaries	1,022,668	-
Shareholders' Equity		
Common stock, \$0.01 par value:		
authorized 300,000,000 shares; issued 119,439,272 shares and outstanding 117,284,487 shares at March 31, 2006; issued 107,973,436 shares and outstanding 97,654,697 shares at December 31, 2005	1,194	1,080
Paid in capital	1,225,134	1,044,283
Unearned compensation	-	(105)
Accumulated other comprehensive loss (Note F)	(505)	(56,991)
Retained earnings	1,188,046	1,085,845
Treasury stock, at cost: 2,154,785 shares at March 31, 2006 and 10,318,739 shares at December 31, 2005	(58,819)	(279,355)
Total Shareholders' Equity	2,355,050	1,794,757
Total Liabilities and Shareholders' Equity	\$ 10,731,432	\$ 10,013,466

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

<i>(Unaudited)</i>	Three Months Ended	
	March 31,	
	2006	2005
Operating Activities	<i>(Thousands of Dollars)</i>	
Net income	\$ 129,492	\$ 107,664
Depreciation, depletion, and amortization	69,426	43,217
Gain on sale of assets	(1,305)	(54)
Minority interest in income of consolidated subsidiaries	45,497	-
Income from equity investments, net	(6,472)	367
Deferred income taxes	38,623	13,545
Stock-based compensation expense	1,510	2,633
Allowance for doubtful accounts	4,182	6,040
Changes in assets and liabilities (net of acquisition and disposition effects):		
Accounts and notes receivable	780,136	163,425
Inventories	280,042	292,126
Unrecovered purchased gas costs	(27,081)	(3,617)
Commodity exchanges	(22,174)	-
Deposits	48,202	(38,412)
Regulatory assets	10,360	(4,898)
Accounts payable and accrued liabilities	(471,980)	(36,213)
Energy marketing and risk management assets and liabilities	(62,480)	375
Other assets and liabilities	(3,648)	(26,602)
Cash Provided by Operating Activities	812,330	519,596
Investing Activities		
Changes in other investments, net	10,815	(23,805)
Capital expenditures	(64,553)	(58,312)
Other investing activities	1,102	(567)
Cash Used in Investing Activities	(52,636)	(82,684)
Financing Activities		
Borrowing (repayment) of notes payable, net	(1,027,500)	44,500
Termination of interest rate swaps	-	(20,212)
Payment of debt	(29,258)	(335,324)
Equity unit conversion	402,447	-
Repurchase of common stock	(1,408)	(65,282)
Issuance of common stock	1,333	4,875
Dividends paid	(27,344)	(26,021)
Distributions to minority interests	(50,855)	-
Contributions from minority interests	3,099	-
Other financing activities	(44,895)	(13,411)
Cash Used in Financing Activities	(774,381)	(410,875)
Change in Cash and Cash Equivalents	(14,687)	26,037
Cash and Cash Equivalents at Beginning of Period	7,915	9,458
Cash of Previously Unconsolidated Subsidiaries	43,572	-
Cash and Cash Equivalents at End of Period	\$ 36,800	\$ 35,495

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

<i>(Unaudited)</i>	Common Stock Issued	Common Stock	Paid in Capital	Unearned Compensation
	<i>(Shares)</i>		<i>(Thousands of Dollars)</i>	
December 31, 2005	107,973,436	\$1,080	\$ 1,044,283	\$ (105)
Net income	-	-	-	-
Other comprehensive income	-	-	-	-
Total comprehensive income				
Equity unit conversion	11,208,998	112	177,571	-
Repurchase of common stock	-	-	-	-
Common stock issuance				
pursuant to various plans	256,838	2	1,928	-
Stock-based employee compensation expense	-	-	1,352	158
Common stock dividends - \$0.28 per share	-	-	-	(53)
March 31, 2006	119,439,272	\$1,194	\$ 1,225,134	\$ -

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries

**CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(Continued)**

<i>(Unaudited)</i>	Accumulated Other Comprehensive Loss	Retained Earnings	Treasury Stock	Total
		<i>(Thousands of Dollars)</i>		
December 31, 2005	\$ (56,991)	\$ 1,085,845	\$ (279,355)	\$ 1,794,757
Net income	-	129,492	-	129,492
Other comprehensive income	56,486	-	-	56,486
Total comprehensive income				<u>185,978</u>
Equity unit conversion	-	-	224,764	402,447
Repurchase of common stock	-	-	(4,228)	(4,228)
Common stock issuance pursuant to various plans	-	-	-	1,930
Stock-based employee compensation expense	-	-	-	1,510
Common stock dividends - \$0.28 per share	-	(27,291)	-	(27,344)
March 31, 2006	\$ (505)	\$ 1,188,046	\$ (58,819)	\$ 2,355,050

ONEOK, Inc. and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

A. SUMMARY OF ACCOUNTING POLICIES

Our accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America and reflect all adjustments that, in our opinion, are necessary for a fair presentation of the results for the interim periods presented. All such adjustments are of a normal recurring nature. Due to the seasonal nature of our business, the results of operations for the three months ended March 31, 2006, are not necessarily indicative of the results that may be expected for a twelve-month period. These unaudited consolidated financial statements should be read in conjunction with our audited consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2005.

Our accounting policies are consistent with those disclosed in Note A of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2005, except as described below.

Significant Accounting Policies

Consolidation - The consolidated financial statements include the accounts of ONEOK, Inc. and our subsidiaries over which we have control. All significant intercompany accounts and transactions have been eliminated in consolidation. Investments in affiliates are accounted for on the equity method if we have the ability to exercise significant influence over operating and financial policies of our investee. Investments in affiliates are accounted for on the cost method if we do not have the ability to exercise significant influence over operating and financial policies of our investee.

In June 2005, the Financial Accounting Standards Board (FASB) ratified the consensus reached in Emerging Issues Task Force (EITF) Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights" (EITF 04-5). EITF 04-5 presumes that a general partner controls a limited partnership and therefore should consolidate the partnership in the financial statements of the general partner. Effective January 1, 2006, we were required to consolidate Northern Border Partners, LP's (Northern Border Partners) operations in our consolidated financial statements, and we elected to use the prospective method. Accordingly, prior period financial statements have not been restated. The adoption of EITF 04-5 did not have an impact on our net income; however, reported revenues, costs and expenses reflect the operating results of Northern Border Partners.

Share-Based Payment - In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123R, "Share-Based Payment" (Statement 123R). Statement 123R requires companies to expense the fair value of share-based payments net of estimated forfeitures. We adopted Statement 123R as of January 1, 2006, and elected to use the modified prospective method. Statement 123R did not have a material impact on our financial statements as we have been expensing share-based payments since our adoption of Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure" (Statement 148) on January 1, 2003. Awards granted after the adoption of Statement 123R are expensed under the requirements of Statement 123R, while equity awards granted prior to the adoption of Statement 123R will continue to be expensed under Statement 148. We recognized other income of \$1.7 million upon adoption of Statement 123R.

Inventory - In September 2005, the FASB ratified the consensus reached in EITF Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty" (EITF 04-13). EITF 04-13 defines when a purchase and a sale of inventory with the same party that operates in the same line of business should be considered a single nonmonetary transaction. EITF 04-13 is effective for new arrangements that a company enters into in periods beginning after March 15, 2006. We completed our review of the applicability of EITF 04-13 to our operations and determined that its impact was immaterial to our consolidated financial statements.

Property - The following table sets forth property, by segment, for the periods presented.

	March 31,	December 31,
	2006	2005
	<i>(Thousands of dollars)</i>	
Gathering and Processing	\$ 781,344	\$ 778,022
Natural Gas Liquids	500,790	497,836
Pipelines and Storage	1,152,620	1,136,821
Energy Services	7,688	7,690
Distribution	3,046,015	3,016,668
Northern Border Partners	3,018,800	-
Other	140,937	138,328
Property, plant and equipment	8,648,194	5,575,365
Accumulated depreciation, depletion and amortization	2,718,333	1,581,138
Net property, plant and equipment	\$5,929,861	\$3,994,227

Income Taxes - Deferred income taxes are recognized for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. The effect on deferred taxes of a change in tax rates is deferred and amortized for operations regulated by the Oklahoma Corporation Commission (OCC), Kansas Corporation Commission (KCC), Texas Railroad Commission (RRC) and various municipalities in Texas. For all other operations, the effect is recognized in income in the period that includes the enactment date. We continue to amortize previously deferred investment tax credits for ratemaking purposes over the period prescribed by the OCC, KCC, RRC and various municipalities in Texas.

Regulation - Our intrastate natural gas transmission pipelines and distribution operations are subject to the rate regulation and accounting requirements of the OCC, KCC, RRC and various municipalities in Texas. Other transportation activities are subject to regulation by the Federal Energy Regulatory Commission (FERC). Oklahoma Natural Gas, Kansas Gas Service, Texas Gas Service and portions of our Pipelines and Storage segment and Northern Border Partners segment follow the accounting and reporting guidance contained in Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (Statement 71). During the rate-making process, regulatory authorities may require us to defer recognition of certain costs to be recovered through rates over time as opposed to expensing such costs as incurred. This allows us to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. Accordingly, actions of the regulatory authorities could have an affect on the amount recovered from rate payers. Any difference in the amount recoverable and the amount deferred would be recorded as income or expense at the time of the regulatory action. If all or a portion of the regulated operations becomes no longer subject to the provisions of Statement 71, a write-off of regulatory assets and stranded costs may be required.

In June 2005, the FERC issued guidance describing how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation's Office of Pipeline Safety. Under the guidance, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. We have certain companies that have rate orders in place to authorize the deferral of these costs and, where applicable, we defer these costs in accordance with Statement 71. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial and mitigation actions to correct an identified condition can be capitalized. The guidance was effective January 1, 2006, and was applied prospectively.

Other

Pension and Postretirement Employee Benefits - In March 2006, the FASB issued an exposure draft on accounting for pension and postretirement medical benefits. The final standard for the first phase of this project is expected to be issued in the third quarter of 2006, with implementation required for years ending after December 15, 2006. Based on the exposure draft, we could be required to record a balance sheet liability equal to the difference between our benefit obligations and plan assets. If this requirement had been in place at December 31, 2005, we would have been required to record unrecognized losses of \$124.8 million and \$78.8 million for pension and postretirement benefits, respectively, on our consolidated balance sheet as accumulated other comprehensive loss.

Reclassifications - Certain amounts in our consolidated financial statements have been reclassified to conform to the 2006 presentation. These reclassifications did not impact previously reported net income or shareholders' equity. Prior periods have been adjusted to reflect the sale of our Production segment and the pending sale of our Spring Creek power plant as discontinued operations. See Note C for additional information.

B. ACQUISITIONS AND DIVESTITURES

In April 2006, we sold and transferred certain assets comprising our Gathering and Processing segment, Natural Gas Liquids segment, and Pipelines and Storage segment to Northern Border Partners for approximately \$3 billion in cash and Class B limited partner units in Northern Border Partners. We also purchased, through Northern Plains, from an affiliate of TransCanada Corporation (TransCanada) its 17.5 percent general partner interest in Northern Border Partners for \$40 million, less \$10 million for expenses associated with the transfer of operating responsibility of the Northern Border Pipeline Company (Northern Border Pipeline) to TransCanada for a net payment of \$30 million. This purchase results in us owning 100 percent of the two percent general partner interest in Northern Border Partners.

We received approximately \$1.35 billion in cash, subject to adjustment for certain working capital items, and approximately 36.5 million Class B limited partner units from Northern Border Partners. The Class B limited partner units and related general partner interest contribution were valued at approximately \$1.65 billion. This transfer of assets includes the natural gas liquids assets we purchased from Koch Industries, Inc. (Koch) in July 2005 for \$1.35 billion. We did not recognize a gain on the transaction, as the transfer of assets was accounted for at historical cost since these transactions were between affiliates under common control. Following the completion of the transactions, we own approximately 37.0 million common and Class B limited partner units and 100 percent of the two percent Northern Border Partners' general partner interest. Our overall interest in Northern Border Partners, including the two percent general partner interest, has increased to 45.7 percent.

In April 2006, our Northern Border Partners segment completed the sale of a 20 percent partnership interest in Northern Border Pipeline to TC PipeLines Intermediate Limited Partnership (TC PipeLines), an affiliate of TransCanada, for approximately \$297 million. We each now own a 50 percent interest in Northern Border Pipeline, with an affiliate of TransCanada becoming operator of the pipeline in April 2007. Following the completion of the transactions, Northern Border Partners will no longer consolidate Northern Border Pipeline in their financial statements. Instead, their interest in Northern Border Pipeline will be accounted for as an investment under the equity method. This change will be retroactive to January 1, 2006.

In April 2006, our Northern Border Partners segment acquired the remaining 66 2/3 percent interest in Guardian Pipeline LLC (Guardian Pipeline) for approximately \$77 million, increasing its ownership interest to 100 percent. Northern Border Partners used borrowings from its credit facility to fund its acquisition of the additional interest in Guardian Pipeline. Following the completion of the transaction, Northern Border Partners will consolidate Guardian Pipeline in their financial statements. Prior to the transaction, Guardian Pipeline was accounted for by Northern Border Partners as an investment under the equity method.

In October 2005, we entered into an agreement to sell our Spring Creek power plant to Westar Energy, Inc. (Westar) for approximately \$53 million. The transaction requires FERC approval and is expected to be completed in 2006. The 300-megawatt gas-fired merchant power plant was built in 2001 to supply electrical power during peak periods using gas-powered turbine generators. The financial information related to the properties held for sale is reflected as a discontinued component in our consolidated financial statements. All periods presented have been restated to reflect the discontinued component. See Note C for additional information.

In July 2005, we completed our acquisition of the natural gas liquids businesses owned by Koch for approximately \$1.33 billion, net of working capital and cash received. This transaction included Koch Hydrocarbon, LP's entire mid-continent natural gas liquids fractionation business; Koch Pipeline Company, LP's natural gas liquids pipeline distribution systems; Chisholm Pipeline Holdings, Inc., which has a 50 percent ownership interest in Chisholm Pipeline Company; MBFF, LP, which owns an 80 percent interest in the 160,000 barrel per day fractionator at Mont Belvieu, Texas; and Koch Vesco Holdings, LLC, an entity that owns a 10.2 percent interest in Venice Energy Services Company, LLC (VESCO). These assets are included in our consolidated financial statements beginning on July 1, 2005.

The unaudited pro forma information in the table below presents a summary of our consolidated results of operations as if our acquisition of the Koch natural gas liquids businesses had occurred at the beginning of the periods presented. The results do not necessarily reflect the results that would have been obtained if our acquisition had actually occurred on the dates indicated or results that may be expected in the future.

Pro Forma	
Three Months Ended	
March 31, 2005	
<i>(Thousand of Dollars, except per share amounts)</i>	
Net revenues	\$ 407,539
Net income	\$ 113,982
Net earnings per share, basic	\$ 1.10
Net earnings per share, diluted	\$ 1.03

C. DISCONTINUED OPERATIONS

In September 2005, we completed the sale of our Production segment to TXOK Acquisition, Inc. for \$645 million, before adjustments, and recognized a pre-tax gain on the sale of approximately \$240.3 million. The gain reflects the cash received less adjustments, selling expenses and the net book value of the assets sold. The proceeds from the sale were used to reduce debt. Our Board of Directors had approved the potential sale in July 2005, which resulted in our Production segment being classified as held for sale beginning July 1, 2005.

Additionally, in the third quarter of 2005, we made the decision to sell our Spring Creek power plant and exit the power generation business. We entered into an agreement to sell our Spring Creek power plant to Westar for approximately \$53 million. The transaction requires FERC approval and is expected to be completed in 2006. The 300-megawatt gas-fired merchant power plant was built in 2001 to supply electrical power during peak periods using gas-powered turbine generators. The proceeds from this sale will be used to purchase other assets, repurchase ONEOK shares or retire debt.

These components of our business are accounted for as discontinued operations in accordance with Statement 144. Accordingly, amounts in our financial statements and related notes for all periods shown relating to our Production segment and our power generation business are reflected as discontinued operations.

The amounts of revenue, costs and income taxes reported in discontinued operations are as follows.

	Three Months Ended	
	March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Operating revenues	\$ 1,849	\$ 45,823
Cost of sales and fuel	1,118	16,655
Net margin	731	29,168
Operating costs	218	7,676
Depreciation, depletion and amortization	-	8,280
Operating income	513	13,212
Other income (expense), net	-	(5)
Interest expense	904	3,712
Income taxes	(152)	3,609
Income (loss) from operations of discontinued components, net	\$ (239)	\$ 5,886

The following table discloses the major classes of discontinued assets and liabilities included in our Consolidated Balance Sheet for the periods indicated.

	March 31, 2006	December 31, 2005
<i>(Thousands of dollars)</i>		
Assets		
Property, plant and equipment, net	\$ 50,937	\$ 50,937
Deferred income taxes	7,896	9,151
Investments and other	4,168	3,823
Assets of Discontinued Component	\$ 63,001	\$ 63,911
Liabilities		
Accounts payable	\$ 316	\$ 1,043
Other liabilities	1,647	1,421
Liabilities of Discontinued Component	\$ 1,963	\$ 2,464

D. ENERGY MARKETING AND RISK MANAGEMENT ACTIVITIES AND FAIR VALUE OF FINANCIAL INSTRUMENTS

Accounting Treatment - We account for derivative instruments and hedging activities in accordance with Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (Statement 133). Under Statement 133, entities are required to record all derivative instruments at fair value. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it. If the derivative instrument does not qualify or is not designated as part of a hedging relationship, we account for changes in fair value of the derivative instrument in earnings as they occur. We record these changes in fair value as operating revenues in our Consolidated Statements of Income. If certain conditions are met, entities may elect to designate a derivative instrument as a hedge of exposure to changes in fair values, cash flows or foreign currencies. For hedges of exposure to changes in fair value, the gain or loss on the derivative instrument is recognized in earnings in the period of change together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. The difference between the change in fair value of the derivative instrument and the change in fair value of the hedged item represents hedge ineffectiveness. For hedges of exposure to changes in cash flow, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of other comprehensive loss and is subsequently reclassified into earnings when the forecasted transaction affects earnings.

As required by Statement 133, we formally document all relationships between hedging instruments and hedged items, as well as risk management objectives, strategies for undertaking various hedge transactions and methods for assessing and testing correlation and hedge ineffectiveness. We specifically identify the asset, liability, firm commitment or forecasted transaction that has been designated as the hedged item. We assess the effectiveness of hedging relationships, both at the inception of the hedge and on an ongoing basis.

Refer to Note D of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2005, for additional discussion.

Fair Value Hedges

In prior years, we terminated various interest rate swap agreements. The net savings from the termination of these swaps is being recognized in interest expense over the terms of the debt instruments originally hedged. Net interest expense savings for the first quarter of 2006 for all terminated swaps was \$3.1 million and the remaining net savings for all terminated swaps will be recognized over the following periods:

	Northern Border Partners		
	ONEOK	Partners	Total
	<i>(Millions of dollars)</i>		
Remainder of 2006	\$ 5.1	\$ 2.4	\$ 7.5
2007	6.6	3.4	10.0
2008	6.6	3.6	10.2
2009	5.6	3.8	9.4
2010	5.5	4.0	9.5
Thereafter	15.3	0.8	16.1

Currently, \$490 million of fixed rate debt is swapped to floating. The floating rate debt is based on both the three- and six-month London InterBank Offered Rate (LIBOR), depending upon the swap. Based on the actual performance through March 31, 2006, the weighted average interest rate on the \$490 million of debt increased from 6.64 percent to 7.01 percent. At March 31, 2006, we recorded a net liability of \$21.2 million to recognize the interest rate swaps at fair value. Long-term debt was decreased by \$21.2 million to recognize the change in the fair value of the related hedged liability.

Our Energy Services segment uses basis swaps to hedge the fair value of certain firm transportation commitments. Net gains or losses from the fair value hedges are recorded to cost of sales and fuel. The ineffectiveness related to these hedges was \$5.3 million and \$0.3 million for the three months ended March 31, 2006 and 2005, respectively.

Cash Flow Hedges

Our Energy Services segment uses futures and swaps to hedge the cash flows associated with our anticipated purchases and sales of natural gas and cost of fuel used in transportation of gas. Accumulated other comprehensive loss at March 31, 2006, includes losses of approximately \$0.4 million, net of tax, related to these hedges that will be realized within the next 38 months. We will recognize \$2.5 million in net gains over the next 12 months, and we will recognize net losses of \$2.9 million thereafter. Our Gathering and Processing segment, Natural Gas Liquids segment and Northern Border Partners segment periodically enter into derivative instruments to hedge the cash flows associated with our exposure to changes in the price of natural gas, natural gas liquids (NGLs) and condensate. At March 31, 2006, these segments did not have material amounts in accumulated other comprehensive loss for derivative instruments in place to hedge natural gas, NGLs and condensate purchases and sales.

Net gains and losses are reclassified out of accumulated other comprehensive loss to operating revenues or cost of sales and fuel when the anticipated purchase or sale occurs. Ineffectiveness related to these cash flow hedges resulted in a gain of approximately \$7.2 million for the three months ended March 31, 2006. Ineffectiveness related to these cash flow hedges for the three months ended March 31, 2005, resulted in a loss of approximately \$0.6 million. There were no losses during the three months ended March 31, 2006, due to the discontinuance of cash flow hedge treatment.

E. GOODWILL AND INTANGIBLES

In accordance with EITF 04-5, we consolidated our Northern Border Partners segment beginning January 1, 2006. The annual test for goodwill for our Northern Border Partners segment was performed as of October 1, 2005, and there was no impairment indicated.

We performed the annual test of goodwill as of January 1, 2006, for our Gathering and Processing, Pipelines and Storage, Energy Services, and Distribution segments, and there was no impairment indicated. Our Natural Gas Liquids segment was formed on July 1, 2005, with our acquisition of the natural gas liquids assets from Koch and the transfer of our existing natural gas liquids marketing business. During the period from July 1, 2005 through January 1, 2006, there was no indication of goodwill impairment associated with our Natural Gas Liquids segment. The following table reflects the changes in the carrying amount of goodwill for the periods indicated.

	Balance December 31, 2005	Goodwill Additions	Adoption of EITF 04-5	Balance March 31, 2006
	<i>(Thousands of dollars)</i>			
Gathering and Processing	\$ 15,604	\$ -	\$ -	\$ 15,604
Natural Gas Liquids	173,945	-	-	173,945
Pipelines and Storage	22,036	2,105	-	24,141
Energy Services	10,255	-	-	10,255
Distribution	158,554	-	-	158,554
Northern Border Partners	-	-	184,843	184,843
Goodwill	\$ 380,394	\$ 2,105	\$ 184,843	\$ 567,342

The adoption of EITF 04-5 resulted in \$152.8 million of Northern Border Partners goodwill being included in our consolidated balance sheet and \$32.0 million of goodwill which was previously recorded as our equity investment in Northern Border Partners. The goodwill addition to our Pipelines and Storage segment relates to an incremental one percent acquisition in an affiliate that was previously accounted for under the equity method. Following our acquisition, we began consolidating the entity.

Intangible assets primarily relate to contracts acquired through our acquisition of the natural gas liquids businesses from Koch and are being amortized over an aggregate weighted-average period of 40 years. The aggregate amortization expense for each of the next five years is estimated to be approximately \$7.7 million. The following tables reflect the gross carrying amount and accumulated amortization of intangibles at March 31, 2006.

	Intangibles, gross	Accumulated Amortization	Intangibles, net
	<i>(Thousands of dollars)</i>		
Natural Gas Liquids	\$ 292,000	\$ (5,474)	\$ 286,526
Pipelines and Storage	14,650	(275)	14,375
Northern Border Partners	123,021	-	123,021
Intangibles	\$ 429,671	\$ (5,749)	\$ 423,922

	Balance December 31, 2005	Amortization	Balance March 31, 2006
	<i>(Thousands of dollars)</i>		
Natural Gas Liquids	\$ (3,649)	\$ (1,825)	\$ (5,474)
Pipelines and Storage	(184)	(91)	(275)
Accumulated amortization	\$ (3,833)	\$ (1,916)	\$ (5,749)

The adoption of EITF 04-5 resulted in \$123.0 million of intangibles, which was previously recorded as our equity investment in Northern Border Partners. The intangibles relate to our general partner interest in Northern Border Partners. The intangibles have an indefinite life and accordingly, are not subject to amortization, but are subject to impairment testing.

F. COMPREHENSIVE INCOME

The tables below give an overview of comprehensive income for the periods indicated.

	Three Months Ended March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Net income	\$ 129,492	\$ 107,664
Unrealized gains (losses) on derivative instruments	\$ 80,835	\$ (81,127)
Unrealized holding losses arising during the period	-	(606)
Realized gains (losses) in net income	<u>11,282</u>	<u>(11,919)</u>
Other comprehensive income (loss) before taxes	92,117	(93,652)
Income tax benefit (provision) on other comprehensive income (loss)	<u>(35,631)</u>	36,212
Other comprehensive income (loss)	<u>56,486</u>	<u>(57,440)</u>
Comprehensive income	<u>\$ 185,978</u>	<u>\$ 50,224</u>

Accumulated other comprehensive loss at March 31, 2006 and 2005, primarily includes unrealized gains and losses on derivative instruments and minimum pension liability adjustments.

G. CAPITAL STOCK

Stock Repurchase Plan - A total of 7.5 million shares have been repurchased to date pursuant to a plan approved by our Board of Directors. The plan originally approved by our Board of Directors in January 2005, was extended in November 2005, to allow us to purchase up to a total of 15 million shares of our common stock on or before November 2007. During the first quarter of 2006, we did not repurchase shares of our common stock under this plan.

Dividends - Quarterly dividends paid on our common stock for shareholders of record as of the close of business on January 31, 2006, were \$0.28 per share. In April 2006, our Board of Directors announced an increase in our quarterly dividend to \$0.30 per share payable in the second quarter of 2006.

Equity Units - On February 16, 2006, we successfully settled our 16.1 million equity units with 19.5 million shares of our common stock. Of this amount, 8.3 million shares were issued from treasury stock and approximately 11.2 million shares were newly issued. Holders of the equity units received 1.2119 shares of our common stock for each equity unit they owned. The number of shares that we issued for each stock purchase contract was determined based on our average closing price over the 20 trading day period ending on the third trading day prior to February 16, 2006. With the settlement, we received \$402.4 million in cash, which was used to pay down our short-term bridge financing agreement.

H. LINES OF CREDIT AND SHORT-TERM NOTES PAYABLE

Short-term Bridge Financing Agreement - On July 1, 2005, we borrowed \$1.0 billion under ONEOK's new short-term bridge financing agreement to assist in financing our acquisition of assets from Koch. We funded the remaining acquisition cost through our commercial paper program. During the three months ended March 31, 2006, we repaid the remaining \$900 million under our short-term bridge financing agreement.

Five-year Credit Agreement - In April 2006, we amended ONEOK's 2004 \$1.2 billion five-year credit agreement to accommodate the transaction with Northern Border Partners. This amendment included changes to the material adverse effect representation, the burdensome agreement representation and the covenant regarding maintenance of control of Northern Border Partners.

Northern Border Partners - In May 2005, Northern Border Pipeline entered into a \$175 million five-year credit agreement (2005 Pipeline Credit Agreement). In March 2006, Northern Border Partners amended and restated its \$500 million revolving credit agreement (2006 Partnership Credit Agreement) and increased the amount they can borrow under the agreement to \$750 million. Both of the revolving credit facilities permit Northern Border Partners and Northern Border Pipeline to choose the lender's base rate or the London Interbank Offered Rate (LIBOR) plus a spread (based on each of their long-term unsecured debt ratings) as the interest rate on their outstanding borrowings, specify the portion of the borrowings to be covered by specific interest rate options and specify the interest rate period. The 2005 Pipeline Credit Agreement and the 2006 Partnership Credit Agreement are to be used for capital expenditures, acquisitions, general business purposes and refinancing existing indebtedness.

In April 2006, Northern Border Partners entered into a \$1.1 billion 364-day credit agreement and borrowed \$1.05 billion to fund a portion of its purchase of certain assets comprising our Gathering and Processing segment, Natural Gas Liquids segment, and Pipelines and Storage segment. Until May 6, 2006, Northern Border Partners can make one additional borrowing of up to \$50 million for purposes of making payments related to this transaction. The interest rate is based, at their election, on either (i) the higher of prime or one-half of one percent above the Federal Funds Rate, which is the rate that banks charge each other for the overnight borrowing of funds, or (ii) the Eurodollar rate plus a set number of basis points based on Northern Border Partners' current long-term unsecured debt ratings by Moody's Investor Services (Moody's) and Standard and Poor's Ratings Group (S&P). Northern Border Partners anticipates permanent financing of its acquisition to come from proceeds resulting from the future issuance of long-term debt.

General - ONEOK's five-year credit agreement, Northern Border Pipeline's 2005 Pipeline Credit Agreement, and Northern Border Partners' 2006 Partnership Credit Agreement and \$1.1 billion 364-day credit agreements contain customary affirmative and negative covenants, including covenants relating to liens, investments, fundamental changes in our business, changes in the nature of our business, transactions with affiliates, the use of proceeds and a covenant that prevents us from restricting our subsidiaries' ability to pay dividends. ONEOK's five-year credit agreement also has limitations on our debt-to-capital ratio and a limit on investments in master limited partnerships. The debt covenant calculations in ONEOK's five-year credit agreement exclude the debt of Northern Border Pipeline and Northern Border Partners, since their lenders have no recourse against ONEOK. Northern Border Pipeline's and Northern Border Partners' agreements also have limitations on the interest coverage ratio and their leverage ratio. The Northern Border Partners' \$1.1 billion 364-day credit agreement also contains mandatory prepayment provisions upon the sale of assets or issuance of debt or equity by Northern Border Partners. At March 31, 2006, ONEOK, Northern Border Pipeline and Northern Border Partners were in compliance with all covenants.

ONEOK had \$128 million in letters of credit and \$507 million of commercial paper outstanding at March 31, 2006. At March 31, 2006, Northern Border Partners had \$231 million outstanding under the 2006 Partnership Credit Agreement at a weighted average interest rate of 5.4 percent and Northern Border Pipeline had \$7 million outstanding under the 2005 Pipeline Credit Agreement at a weighted average interest rate of 5.2 percent.

I. LONG-TERM DEBT

The following table sets forth our long-term debt for the periods indicated.

	March 31, 2006	December 31, 2005
<i>(Thousands of dollars)</i>		
ONEOK		
5.51% due 2008	\$ 402,303	\$ 402,303
6.0% due 2009	100,000	100,000
7.125% due 2011	400,000	400,000
5.2% due 2015	400,000	400,000
6.4% due 2019	92,885	92,921
6.5% due 2028	92,118	92,246
6.875% due 2028	100,000	100,000
6.0% due 2035	400,000	400,000
Other	5,625	5,732
	<u>1,992,931</u>	<u>1,993,202</u>
Northern Border Partners		
8.875% due 2010	250,000	-
7.10% due 2011	225,000	-
	<u>475,000</u>	<u>-</u>
Northern Border Pipeline		
6.25%, due 2007	150,000	-
7.75% due 2009	200,000	-
7.50% due 2021	250,000	-
	<u>600,000</u>	<u>-</u>
Total long-term notes payable	3,067,931	1,993,202
Change in fair value of hedged debt	43,694	39,211
Unamortized debt premium	(1,020)	(1,797)
Current maturities	(6,551)	(6,546)
Long-term debt	<u>\$ 3,104,054</u>	<u>\$ 2,024,070</u>

The aggregate maturities of long-term debt outstanding at March 31, 2006 are shown below.

	ONEOK	Northern Border Partners	Northern Border Pipeline	Total
<i>(In Millions)</i>				
2006	\$ 6.6	\$ -	\$ -	\$ 6.6
2007	6.6	-	150.0	156.6
2008	408.9	-	-	408.9
2009	107.5	-	200.0	307.5
2010	6.3	250.0	-	256.3

Additionally, \$185.0 million of ONEOK's debt is callable at par at our option from now until maturity, which is 2019 for \$92.9 million and 2028 for \$92.1 million. Certain debt agreements have negative covenants that relate to liens and sale/leaseback transactions.

J. EMPLOYEE BENEFIT PLANS

The tables below provide the components of net periodic benefit cost for our pension and other postretirement benefit plans.

	Pension Benefits		Postretirement Benefits	
	Three Months Ended		Three Months Ended	
	March 31,		March 31,	
	2006	2005	2006	2005
Components of Net Periodic Benefit Cost	<i>(Thousands of Dollars)</i>			
Service cost	\$ 5,267	\$ 4,941	\$ 1,583	\$ 1,765
Interest cost	10,871	10,758	3,539	3,567
Expected return on assets	(14,396)	(14,927)	(1,141)	(1,086)
Amortization of unrecognized net asset at adoption	-	-	797	864
Amortization of unrecognized prior service cost	378	361	(571)	118
Amortization of loss	3,353	2,126	2,271	1,617
Net periodic benefit cost	\$ 5,473	\$ 3,259	\$ 6,478	\$ 6,845

Contributions - For the three months ended March 31, 2006, contributions of \$0.4 million and \$12.1 million were made to our pension plan and other postretirement benefit plan, respectively. For 2006, we anticipate total contributions to our defined benefit pension plan and postretirement benefit plan to be \$1.5 million and \$17.3 million, respectively. Our pay-as-you-go other postretirement benefit plan costs were \$3.1 million for the three months ended March 31, 2006, and we expect our total pay-as-you-go costs for 2006 to be \$14.0 million.

K. COMMITMENTS AND CONTINGENCIES

Leases - Our operating leases include a gas processing plant, office buildings, vehicles and equipment. The following table sets forth the future minimum lease payments under non-cancelable operating leases for each of the following years.

	Northern Border		
	ONEOK	Partners	Total
	<i>(In Millions)</i>		
2006	\$ 60.0	\$ 3.8	\$ 63.8
2007	43.8	3.5	47.3
2008	41.5	3.4	44.9
2009	38.4	2.5	40.9
2010	36.1	2.2	38.3

The amounts in the ONEOK column above include the minimum lease payments relating to the lease of a gas processing plant for which we have a liability as a result of uneconomic lease terms.

Environmental - We are subject to multiple environmental laws and regulations affecting many aspects of present and future operations, including air emissions, water quality, wastewater discharges, solid wastes and hazardous material and substance management. These laws and regulations generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties and/or interruptions in our operations that could be material to the results of operations. If an accidental leak or spill of hazardous materials occurs from our lines or facilities, in the process of transporting natural gas or NGLs, or at any facility that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including investigation and clean up costs, which could materially affect our results of operations and cash flows. In addition, emission controls required under the Federal Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on our business, financial condition and results of operations.

We own or retain legal responsibility for the environmental conditions at 12 former manufactured gas sites in Kansas. Our expenditures for environmental evaluation and remediation to date have not been significant in relation to the results of operations, and there have been no material effects upon earnings during 2006 related to compliance with environmental regulations. See Note K in our Annual Report on Form 10-K for the year ended December 31, 2005, for additional discussion. There has been no material change to the status of the manufactured gas sites since December 31, 2005.

Black Mesa Pipeline - On December 31, 2005, our Northern Border Partners segment's Black Mesa Pipeline was temporarily shut down due to the expiration of our coal slurry transportation contract. The Mohave Generating Station co-owners, the Hopi Tribe, the Navajo Nation, Peabody Western Coal Company and other interested parties continue to negotiate water and coal supply issues. Black Mesa Pipeline is working to resolve coal slurry transportation issues so that operations may resume in the future. If there are successful resolutions of all of these issues and the project receives a favorable Environmental Impact Statement, we believe our coal slurry pipeline will be reconstructed in late 2008 and 2009 for an anticipated in-service date during 2010. We anticipate that the capital expenditures for the Black Mesa Pipeline refurbishment project will be in the range of \$175 million to \$200 million, which will be supported by revenue from a new transportation contract. We expect to incur temporary shut down and stand by costs, net of reimbursement, of approximately \$2 million to \$4 million in 2006. Negotiations continue with various parties that may result in the recovery of some of these standby costs. If these issues are not resolved and the Mohave Generating Station is permanently closed, we expect to incur pipeline removal and remediation costs of approximately \$1 million to \$2 million, net of salvage, and to take a non-cash impairment charge of approximately \$10 million related to goodwill and the remaining undepreciated cost of the pipeline. The costs associated with permanent shut down are pre-tax. Depending on how negotiations progress and in accordance with accounting rules, an impairment charge may be required prior to final resolution of the issues concerning Mohave Generating Station even though the project may ultimately proceed.

Other - We are a party to other litigation matters and claims, which are normal in the course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or liquidity.

L. SEGMENTS

Our business segments and the accounting policies of our business segments are the same as those described in Note M and the Summary of Significant Accounting Policies in our Annual Report on Form 10-K for the year ended December 31, 2005, with the exception of the segments described below. Our Distribution segment is comprised of regulated public utilities. Intersegment gross sales are recorded on the same basis as sales to unaffiliated customers. Corporate overhead costs relating to a reportable segment, excluding our Northern Border Partners segment, have been allocated for the purpose of calculating operating income. Our equity method investments do not represent operating segments. We have no single external customer from which we received 10 percent or more of our consolidated gross revenues for the periods covered by this report.

Effective January 1, 2006, we were required to consolidate Northern Border Partners' operations in our consolidated financial statements under EITF 04-5 and we elected to use the prospective method. This resulted in a new segment called Northern Border Partners. Our Northern Border Partners segment gathers, processes and transports natural gas; fractionates NGLs; and transports crushed coal suspended in water. The primary customers for our Northern Border Partners segment include natural gas producers, marketers, industrial facilities, local distribution companies and electric power generating plants.

In September 2005, we completed the sale of our Production segment. Additionally, in the third quarter of 2005, we made the decision to sell our Spring Creek power plant and exit the power generation business. These components of our business are accounted for as discontinued operations in accordance with Statement 144. Our Production segment is included in our Other segment in the tables below, while our power generation business is included in our Energy Services segment.

With our acquisition of assets from Koch on July 1, 2005, we formed a new operating segment called Natural Gas Liquids. This segment consists of our existing natural gas liquids marketing business, which was previously part of our Gathering and Processing segment, and the assets acquired from Koch excluding those natural gas liquids gathering and pipeline distribution assets regulated by the FERC, which have been transferred to our Pipelines and Storage segment. VESCO, also acquired as part of the asset acquisition, was added to our Gathering and Processing segment. Segment results for our Gathering and Processing segment for all prior periods have been restated to reflect the transfer of our existing natural gas liquids marketing business to our Natural Gas Liquids segment.

The following tables set forth certain selected financial information for our operating segments for the periods indicated.

Three Months Ended March 31, 2006	Gathering and Processing	Natural Gas Liquids	Pipelines and Storage	Energy Services
<i>(Thousands of dollars)</i>				
Sales to unaffiliated customers	\$ 10,212	\$ 816,569	\$ 17,452	\$2,111,958
Energy trading revenues, net	-	-	-	7,370
Intersegment sales	316,972	2,854	45,460	195,887
Total Revenues	\$ 327,184	\$ 819,423	\$ 62,912	\$2,315,215
Net margin	\$ 62,416	\$ 33,742	\$ 52,121	\$ 103,154
Operating costs	23,645	11,224	16,790	9,260
Depreciation, depletion and amortization	6,261	5,399	7,583	575
Operating income	\$ 32,510	\$ 17,119	\$ 27,748	\$ 93,319
Income (loss) from operations of discontinued components	\$ -	\$ -	\$ -	\$ (247)
Income from equity investments	\$ -	\$ -	\$ 243	\$ -
Total assets	\$ 1,692,730	\$ 1,467,311	\$ 1,031,233	\$ 2,265,474
Capital expenditures	\$ 3,322	\$ 2,954	\$ 3,576	\$ -

Three Months Ended March 31, 2006	Distribution	Northern Border Partners	Other and Eliminations	Total
<i>(Thousands of dollars)</i>				
Sales to unaffiliated customers	\$ 787,684	\$ 170,912	\$ (3,835)	\$ 3,910,952
Energy trading revenues, net	-	-	-	7,370
Intersegment sales	-	-	(561,173)	-
Total Revenues	\$ 787,684	\$ 170,912	\$ (565,008)	\$ 3,918,322
Net margin	\$ 195,882	\$ 126,801	\$ 1,033	\$ 575,149
Operating costs	90,793	41,730	733	194,175
Depreciation, depletion and amortization	28,186	21,294	128	69,426
Operating income	\$ 76,903	\$ 63,777	\$ 172	\$ 311,548
Income (loss) from operations of discontinued components	\$ -	\$ 8	\$ -	\$ (239)
Income from equity investments	\$ -	\$ 6,229	\$ -	\$ 6,472
Total assets	\$ 2,746,605	\$ 2,488,358	\$ (960,279)	\$ 10,731,432
Capital expenditures	\$ 36,675	\$ 17,806	\$ 220	\$ 64,553

Three Months Ended March 31, 2005	Gathering and Processing	Natural Gas Liquids	Pipelines and Storage	Energy Services
<i>(Thousands of dollars)</i>				
Sales to unaffiliated customers	\$ 55,115	\$ 317,485	\$ 10,850	\$1,536,356
Energy trading revenues, net	-	-	-	9,192
Intersegment sales	299,463	-	29,535	205,908
Total Revenues	\$ 354,578	\$ 317,485	\$ 40,385	\$1,751,456
Net margin	\$ 71,131	\$ 7,257	\$ 30,100	\$ 61,195
Operating costs	29,816	2,415	11,569	8,044
Depreciation, depletion and amortization	8,308	30	4,376	402
Operating income	\$ 33,007	\$ 4,812	\$ 14,155	\$ 52,749
Income (loss) from operations of discontinued components	\$ -	\$ -	\$ -	\$ (848)
Income from equity investments	\$ -	\$ -	\$ 299	\$ -
Total assets	\$ 1,236,401	\$ 198,547	\$ 569,250	\$1,538,170
Capital expenditures	\$ 7,697	\$ 1,696	\$ 1,727	\$ 27

Three Months Ended March 31, 2005	Distribution	Other and Eliminations	Total
<i>(Thousands of dollars)</i>			
Sales to unaffiliated customers	\$ 778,130	\$ (88)	\$ 2,697,848
Energy trading revenues, net	-	-	9,192
Intersegment sales	-	(534,906)	-
Total Revenues	\$ 778,130	\$ (534,994)	\$ 2,707,040
Net margin	\$ 201,220	\$ (506)	\$ 370,397
Operating costs	90,628	(1,670)	140,802
Depreciation, depletion and amortization	29,989	112	43,217
Operating income	\$ 80,603	\$ 1,052	\$ 186,378
Income (loss) from operations of discontinued components	\$ -	\$ 6,734	\$ 5,886
Income from equity investments	\$ -	\$ 2,516	\$ 2,815
Total assets	\$ 2,726,264	\$ 581,287	\$ 6,849,919
Capital expenditures	\$ 27,686	\$ 19,479	\$ 58,312

M. SUPPLEMENTAL CASH FLOW INFORMATION

The following table sets forth supplemental information with respect to our cash flow for the periods indicated.

	Three Months Ended March 31,	
	2006	2005
<i>(Thousands of dollars)</i>		
Cash paid during the period		
Interest, including amounts capitalized	\$ 47,751	\$ 61,789
Income taxes	\$ 123,877	\$ 24,930

Cash paid for interest includes swap terminations and ineffectiveness of \$20.2 million for the three months ended March 31, 2005.

N. SHARE-BASED PAYMENT PLANS

General

Effective January 1, 2006, we adopted Statement 123R. See Note A for additional information. We used a three percent forfeiture rate for all awards outstanding based on historical forfeitures under our share-based payment plans. We use a combination of issuances from treasury and repurchases in the open market to satisfy our share-based payment obligations.

The compensation cost expensed for our share-based payment plans described below was \$2.2 million for the three months ended March 31, 2006, net of tax benefit of \$0.8 million. No compensation cost was capitalized for the three months ended March 31, 2006.

Cash received from the exercise of awards under all share-based payment arrangements was \$0.6 million for the three months ended March 31, 2006. The actual tax benefit realized for the anticipated tax deductions of the exercise of share-based payment arrangements totaled \$0.4 million for the three months ended March 31, 2006. No cash was used to settle awards granted under share-based payment arrangements.

Share-Based Payment Plan Descriptions

The ONEOK, Inc. Long-Term Incentive Plan (the LTIP), ONEOK, Inc. Equity Compensation Plan (Equity Compensation Plan) and the ONEOK, Inc. Stock Compensation Plan for Non-Employee Directors (the DSCP) are described in Note P in our Annual Report on Form 10-K for the year ended December 31, 2005.

Stock Option Activity

The total fair value of stock options vested during the three months ended March 31, 2006, was \$3.7 million. The following table sets forth the stock option activity for employees and non-employee directors for the periods indicated.

	Number of Shares	Weighted Average Exercise Price
Outstanding December 31, 2005	1,952,415	\$ 22.51
Exercised	(106,674)	\$ 20.42
Expired	(1,666)	\$ 18.51
Restored	47,284	\$ 29.74
Outstanding March 31, 2006	1,891,359	\$ 22.81
Exercisable March 31, 2006	1,814,604	\$ 22.52

Stock Options Outstanding					Stock Options Exercisable				
Range of Exercise Prices	Number of Awards	Remaining Life (yrs)	Aggregate		Number of Awards	Remaining Life (yrs)	Aggregate		
			Weighted Average Exercise Price	Intrinsic Value (in 000's)			Weighted Average Exercise Price	Intrinsic Value (in 000's)	
\$13.44 to \$20.16	895,351	5.73	\$ 17.10	\$13,565	893,809	5.73	\$ 17.10	\$13,541	
\$20.17 to \$30.26	700,960	4.55	\$ 25.36	\$ 4,830	647,138	4.56	\$ 25.02	\$ 4,679	
\$30.27 to \$35.49	295,048	4.14	\$ 34.30	\$ -	273,657	4.12	\$ 34.28	\$ -	

The aggregate intrinsic value in the table above represents the total pre-tax intrinsic value based on our closing stock price of \$32.25 as of March 31, 2006, that would have been received by the option holders had all option holders exercised their options as of that date.

The fair value of each option granted was estimated on the date of grant based on the Black-Scholes model using the assumption in the table below.

Volatility (a)	3.88% to 31.06%
Dividend Yield	2.78% to 8.93%
Risk-free Interest Rate	2.44% to 6.53%

(a) - Volatility was based on historical volatility over six months using daily stock price observations.

The expected life of outstanding options ranged from one to ten years based upon experience to date and the make-up of the optionees. As of March 31, 2006, the amount of unrecognized compensation cost related to nonvested stock options was not material.

	March 31, 2006
Weighted average grant date fair value (per share)	\$ 5.49
Intrinsic value of options exercised (thousands of dollars)	\$ 1,047
Fair value of shares granted (thousands of dollars)	\$ 260

Restricted Stock Activity

Awards granted in 2006 and 2003 vest over a three-year period and entitle the grantee to receive shares of our common stock. Awards granted in 2005 and 2004 entitle the grantee to receive two-thirds of the grant in our common stock and one-third of the grant in cash. The equity awards are measured at fair value as if they were vested and issued on the grant-date, generally reduced by expected dividend payments, and adjusted for estimated forfeitures. The portion of the grants that are settled in cash are classified as liability awards with fair value based on the fair market value of our common stock, reduced by expected dividend payments and adjusted for estimated forfeitures, at each reporting date. The total fair value of shares vested during the three months ended March 31, 2006, was \$5.7 million.

The following table sets forth activity for the restricted stock equity awards.

	Number of Shares	Weighted Average Exercise Price
Nonvested December 31, 2005	432,856	\$ 19.58
Released to participants	(190,477)	\$ 16.88
Granted	144,750	\$ 23.82
Forfeited	(11,261)	\$ 20.14
Dividends	1,993	\$ 27.19
Nonvested March 31, 2006	377,861	\$ 22.59

The following table sets forth activity for the restricted stock liability awards.

	Number of Shares	Weighted Average Exercise Price
Nonvested December 31, 2005	119,514	\$ 22.44
Forfeited	(2,912)	\$ 23.19
Nonvested March 31, 2006	116,602	\$ 22.42

As of March 31, 2006, there was \$6.5 million of total unrecognized compensation cost related to our nonvested restricted stock awards, which is expected to be recognized over a weighted-average period of 1.7 years.

	March 31, 2006
Weighted average grant date fair value (per share)	\$ 23.82
Fair value of shares granted (thousands of dollars)	\$ 3,448

Performance Unit Activity

Performance unit awards granted in 2005 and 2004 entitle the grantee to receive two-thirds of the grant in shares of our common stock and one-third of the grant in cash, while awards granted in 2003 entitle the grantee to receive common stock only. These awards vest over a three-year period. The fair values of these performance units that are classified as equity awards were calculated as of the date of grant and remains fixed as equity units upon adoption of Statement 123R. The fair values of the one-third liability portion of the performance units are estimated at each reporting date based on a Monte Carlo model.

Awards granted in 2006 entitle the grantee to receive the grant in shares of our common stock. Under Statement 123R, our 2006 performance unit awards are equity awards with a market based condition, which results in the compensation cost for these awards being recognized over the requisite service period, provided that the requisite service period is rendered, regardless of when, if ever, the market condition is satisfied. The fair value of these performance units was estimated on the grant date based on a Monte Carlo model. The compensation expense on these awards will only be adjusted for changes in forfeitures. The total fair value of shares vested during the three months ended March 31, 2006, was \$4.9 million.

The following table sets forth activity for the performance unit equity awards.

	Number of Units	Weighted Average Exercise Price
Nonvested December 31, 2005	581,847	\$ 21.13
Released to participants	(158,365)	\$ 15.31
Granted	479,000	\$ 25.98
Forfeited	(16,639)	\$ 23.97
Nonvested March 31, 2006	885,843	\$ 24.74

The following table sets forth the assumptions used in the valuation of the 2006 grants.

	February 19, 2006
Volatility (a)	18.80%
Dividend Yield	3.70%
Risk-free Interest Rate	4.32%

(a) - Volatility was based on historical volatility over three years using daily stock price observations.

The following tables set forth activity for the performance unit liability awards and the assumptions used in the valuations.

	Number of Units	Weighted Average Exercise Price
Nonvested December 31, 2005	212,311	\$ 23.31
Released to participants	(166)	\$ 23.36
Forfeited	(8,051)	\$ 23.91
Nonvested March 31, 2006	204,094	\$ 23.29

	January 1, 2006	March 31, 2006
Volatility (a)	19.00%	20.00%
Dividend Yield	3.70%	3.70%
Risk-free Interest Rate	4.37%	4.81%

(a) - Volatility was based on historical volatility over three years using daily stock price observations.

As of March 31, 2006, there was \$18.7 million of total unrecognized compensation cost related to the nonvested performance unit awards, which is expected to be recognized over a weighted-average period of 2.0 years.

	March 31, 2006	
Weighted average grant date fair value (per share)	\$	25.98
Fair value of shares granted (thousands of dollars)	\$	12,444

O. EARNINGS PER SHARE INFORMATION

We compute earnings per common share (EPS) as described in Note Q of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2005.

The following tables set forth the computations of the basic and diluted EPS for the periods indicated.

	Three Months Ended March 31, 2006		
	Income	Shares	Per Share Amount
Basic EPS from continuing operations	<i>(Thousands, except per share amounts)</i>		
Income from continuing operations available for common stock	\$ 129,731	107,143	\$ 1.21
Diluted EPS from continuing operations			
Effect of other dilutive securities:			
Mandatory convertible units	-	2,518	
Options and other dilutive securities	-	1,095	
Income from continuing operations available for common stock and common stock equivalents	\$ 129,731	110,756	\$ 1.17

	Three Months Ended March 31, 2005		
	Income	Shares	Per Share Amount
Basic EPS from continuing operations	<i>(Thousands, except per share amounts)</i>		
Income from continuing operations available for common stock	\$ 101,778	103,666	\$ 0.98
Diluted EPS from continuing operations			
Effect of other dilutive securities:			
Mandatory convertible units	-	6,297	
Options and other dilutive securities	-	1,038	
Income from continuing operations available for common stock and common stock equivalents	\$ 101,778	111,001	\$ 0.92

There were 438,924 and 11,022 option shares excluded from the calculation of diluted EPS for the three months ended March 31, 2006 and 2005, respectively, since their inclusion would be antidilutive for each period.

P. NORTHERN BORDER PARTNERS

Northern Border Partners - At March 31, 2006 and 2005, our investment consisted of an 82.5 percent general partner interest and 500,000 limited partnership units, together representing a 2.7 percent ownership interest in Northern Border Partners. At March 31, 2006, Northern Border Partners' equity consisted of 46,397,214 common units representing a 98.0 percent limited partner interest in Northern Border Partners and a 2.0 percent general partner interest. Under the Northern Border Partners partnership agreement and in conjunction with the issuance of additional common units by Northern Border Partners, the general partners are required to make equity contributions in order to maintain their representative general partner interests.

Under the Northern Border Partners' partnership agreement, distributions are made to their partners with respect to each calendar quarter in an amount equal to 100 percent of available cash. Available cash generally consists of all cash receipts adjusted for cash disbursements and net changes to cash reserves. Available cash will generally be distributed 98.0 percent to limited partners

and 2.0 percent to general partners. As an incentive, the general partners' percentage interest in quarterly distributions is increased after certain specified target levels are met. Under the incentive distribution provisions, the general partners receive:

- 15 percent of amounts distributed in excess of \$0.605 per unit,
- 25 percent of amounts distributed in excess of \$0.715 per unit and
- 50 percent of amounts distributed in excess of \$0.935 per unit.

Northern Border Partners' income is allocated to the general partners and the limited partners in accordance with their respective partnership percentages, after giving effect to any priority income allocations for incentive distributions that are allocated to the general partners. Northern Border Partners paid \$2.8 million to its general partners for the three months ended March 31, 2006 and 2005, respectively. For each of the three months ended March 31, 2006 and 2005, we, as the 82.5 percent general partner, received \$2.3 million from Northern Border Partners. In April 2006, we acquired the remaining 17.5 percent general partner interest from TransCanada, which results in us owning 100 percent of the two percent general partner interest. Based on Northern Border Partners' current cash distribution of \$0.88 per unit and our increased general partner interest, we expect our incentive partner distribution and partner allocation to be approximately \$3.6 million, payable beginning in the third quarter of 2006. See Note B in this Quarterly Report on Form 10-Q for additional discussion of the acquisition of the additional general partner interest.

The quarterly distribution paid by Northern Border Partners in the first quarter of 2006 was \$0.80. In April 2006, Northern Border Partners declared a cash distribution of \$0.88 per unit payable in the second quarter.

Northern Border Pipeline - The Northern Border Pipeline partnership agreement provides that distributions to Northern Border Pipeline's partners, including Northern Border Partners, are to be made on a pro rata basis according to each partner's capital account balance. The Northern Border Pipeline Management Committee determines the amount and timing of such distributions.

Q. SUBSEQUENT EVENT

In May 2006, a subsidiary of Northern Border Partners entered into an agreement with a subsidiary of Williams to form a joint venture called Overland Pass Pipeline Company, LLC (Overland Pass Pipeline Company). Overland Pass Pipeline Company will build a 750-mile natural gas liquids pipeline from Opal, Wyoming to the mid-continent natural gas liquids market center in Conway, Kansas. The pipeline will be designed to transport 110,000 barrels per day of NGLs, which can be increased to 150,000 barrels per day with additional pump facilities. Northern Border Partners will initially own 99 percent of the joint venture, will manage the construction project and will operate the pipeline. Williams will have the option to increase its ownership to 50 percent and become operator within two years of the pipeline becoming operational. Construction of the pipeline is expected to begin in the summer of 2007, with start-up scheduled for early 2008. As part of a long-term agreement, Williams will dedicate its NGL production from two of its gas processing plants in Wyoming to the joint-venture company. Subsidiaries of Northern Border Partners will provide downstream fractionation and transportation services. The pipeline project is estimated to cost approximately \$450 million. In addition, Northern Border Partners plans to invest approximately \$160 million to expand its existing fractionation capabilities and the capacity of its natural gas liquids pipelines. Northern Border Partners' financing for both projects may include a combination of short- or long-term debt or equity. The project requires the approval of various state and regulatory authorities.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE SUMMARY

Operating income for our first quarter of 2006 was \$311.5 million, an increase of \$125.2 million, or 67 percent, compared with the same period in 2005. Diluted earnings per share of common stock from continuing operations (EPS) increased to \$1.17 for the first quarter of 2006 from \$0.92 for the same period in 2005.

We began consolidating our investment in Northern Border Partners, LP (Northern Border Partners) on January 1, 2006, in accordance with Emerging Issues Task Force (EITF) Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights" (EITF 04-5), which resulted in increased operating income of \$63.8 million. See Impact of New Accounting Standards on page 30 for additional information on the consolidation of Northern Border Partners.

Operating income for our Energy Services segment increased \$40.6 million in the first quarter of 2006 compared with the same period in 2005. An increase of \$28.2 million in net margin was due to the effect of improved natural gas basis differentials on transportation contracts. Additionally, increased storage margins of \$9.5 million resulted primarily from increased demand fees.

Our acquisition of the natural gas liquids businesses owned by Koch Industries, Inc. (Koch) in July 2005, accounted for increases in both our Natural Gas Liquids segment and our Pipelines and Storage segment. The sale of natural gas gathering and processing assets located in Texas during December 2005, resulted in decreases in our Gathering and Processing segment offset by higher commodity prices.

On February 14, 2006, we signed agreements to sell and transfer certain assets comprising our Gathering and Processing segment, Natural Gas Liquids segment, and Pipelines and Storage segment to Northern Border Partners for approximately \$3 billion in cash and Class B limited partner units, and to increase our general partner interest to 100 percent of the two percent general partner interest in Northern Border Partners. These transactions were completed on April 6, 2006.

In April 2006, our Board of Directors announced an increase in our quarterly dividend to \$0.30 per share, an increase of seven percent over the \$0.28 per share dividend paid in the first quarter. This is a result of the continued evaluation of our dividend payout in relation to both our financial performance and our peer companies.

Additionally, Northern Border Partners declared an increase in its cash distribution to \$0.88 per unit in April 2006, an increase of ten percent over the \$0.80 per unit distribution paid in the first quarter.

ACQUISITIONS AND DIVESTITURES

In April 2006, we sold and transferred certain assets comprising our Gathering and Processing segment, Natural Gas Liquids segment, and Pipelines and Storage segment to Northern Border Partners for approximately \$3 billion in cash and Class B limited partner units in Northern Border Partners. We also purchased, through Northern Plains, from an affiliate of TransCanada Corporation (TransCanada) its 17.5 percent general partner interest in Northern Border Partners for \$40 million, less \$10 million for expenses associated with the transfer of operating responsibility of the Northern Border Pipeline Company (Northern Border Pipeline) to TransCanada for a net payment of \$30 million. This purchase results in us owning 100 percent of the two percent general partner interest in Northern Border Partners.

We received approximately \$1.35 billion in cash, subject to adjustment for certain working capital items, and approximately 36.5 million Class B limited partner units from Northern Border Partners. The Class B limited partner units and related general partner interest contribution were valued at approximately \$1.65 billion. This transfer of assets includes the natural gas liquids assets we purchased from Koch in July 2005 for \$1.35 billion. We did not recognize a gain on the transaction, as the transfer of assets was accounted for at historical cost since these transactions were between affiliates under common control. Following the completion of the transactions, we own approximately 37.0 million common and Class B limited partner units and 100 percent of the two percent Northern Border Partners' general partner interest. Our overall interest in Northern Border Partners, including the two percent general partner interest, has increased to 45.7 percent.

In April 2006, our Northern Border Partners segment completed the sale of a 20 percent partnership interest in Northern Border Pipeline to TC PipeLines Intermediate Limited Partnership (TC PipeLines), an affiliate of TransCanada, for approximately \$297

million. We each now own a 50 percent interest in Northern Border Pipeline, with an affiliate of TransCanada becoming operator of the pipeline in April 2007. Following the completion of the transactions, Northern Border Partners will no longer consolidate Northern Border Pipeline in their financial statements. Instead, their interest in Northern Border Pipeline will be accounted for as an investment under the equity method. This change will be retroactive to January 1, 2006.

In April 2006, our Northern Border Partners segment acquired the remaining 66 2/3 percent interest in Guardian Pipeline, LLC (Guardian Pipeline) for approximately \$77 million, increasing its ownership interest to 100 percent. Northern Border Partners used borrowings from its credit facility to fund its acquisition of the additional interest in Guardian Pipeline. Following the completion of the transaction, Northern Border Partners will consolidate Guardian Pipeline in their financial statements. Prior to the transaction, Guardian Pipeline was accounted for by Northern Border Partners as an investment under the equity method.

In December 2005, we sold our natural gas gathering and processing assets located in Texas to a subsidiary of Eagle Rock Energy, Inc. for approximately \$527.2 million and recorded a pre-tax gain of \$264.2 million.

In October 2005, we entered into an agreement to sell our Spring Creek power plant to Westar Energy, Inc. (Westar) for approximately \$53 million. The transaction requires Federal Energy Regulatory Commission (FERC) approval and is expected to be completed in 2006. The 300-megawatt gas-fired merchant power plant was built in 2001 to supply electrical power during peak periods using gas-powered turbine generators. The financial information related to the properties held for sale is reflected as a discontinued component in this Report on Form 10-Q. All periods presented have been restated to reflect the discontinued component.

In September 2005, we completed the sale of our Production segment to TXOK Acquisition, Inc. for \$645 million, before adjustments and recognized a pre-tax gain on the sale of approximately \$240.3 million. The gain reflects the cash received less adjustments, selling expenses and the net book value of the assets sold. The proceeds from the sale were used to reduce debt. The financial information related to the properties sold is reflected as a discontinued component in this Report on Form 10-Q. All periods presented have been restated to reflect the discontinued component.

In July 2005, we completed our acquisition of the natural gas liquids businesses owned by Koch for approximately \$1.33 billion, net of working capital and cash received. This transaction included Koch Hydrocarbon, LP's entire mid-continent natural gas liquids fractionation business; Koch Pipeline Company, LP's natural gas liquids pipeline distribution systems; Chisholm Pipeline Holdings, Inc., which has a 50 percent ownership interest in Chisholm Pipeline Company; MBFF, LP, which owns an 80 percent interest in the 160,000 barrel per day fractionator at Mont Belvieu, Texas; and Koch Vesco Holdings, LLC, an entity that owns a 10.2 percent interest in Venice Energy Services Company, LLC (VESCO). These assets are included in our consolidated financial statements beginning on July 1, 2005.

REGULATORY

In June 2005, FERC issued guidance describing how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation's Office of Pipeline Safety. Under the guidance, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. We have certain companies that have rate orders in place to authorize the deferral of these costs and, where applicable, we defer these costs in accordance with Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (Statement 71). Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial and mitigation actions to correct an identified condition can be capitalized. The guidance was effective January 1, 2006, and was applied prospectively.

Several regulatory initiatives impacted the earnings and future earnings potential for our Distribution segment and our Northern Border Partners segment. See discussion of our Distribution segment's regulatory initiatives beginning on page 42 and discussion of our Northern Borders Partners segment's regulatory initiative beginning on page 44.

IMPACT OF NEW ACCOUNTING STANDARDS

In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 123R, "Share-Based Payment" (Statement 123R). Statement 123R requires companies to expense the fair value of share-based payments net of estimated forfeitures. We adopted Statement 123R as of January 1, 2006, and we elected to use the modified prospective method. Statement 123R did not have a material impact on our financial statements as we have been expensing

share-based payments since our adoption of Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure" (Statement 148) on January 1, 2003. Awards granted after the adoption of Statement 123R are expensed under the requirements of Statement 123R, while equity awards granted prior to the adoption of Statement 123R will continue to be expensed under Statement 148. We recognized other income of \$1.7 million upon adoption of Statement 123R.

In June 2005, the FASB ratified the consensus reached in EITF 04-5, which presumes that a general partner controls a limited partnership and therefore should consolidate the partnership in the financial statements of the general partner. Effective January 1, 2006, we were required to consolidate Northern Border Partners' operations in our consolidated financial statements, and we elected to use the prospective method. The adoption of EITF 04-5 did not have an impact on our net income; however, reported revenues, costs and expenses reflect the operating results of Northern Border Partners.

In September 2005, the FASB ratified the consensus reached in EITF Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty" (EITF 04-13). EITF 04-13 defines when a purchase and a sale of inventory with the same party that operates in the same line of business should be considered a single nonmonetary transaction. EITF 04-13 is effective for new arrangements that a company enters into in periods beginning after March 15, 2006. We completed our review of the applicability of EITF 04-13 to our operations and determined that its impact was immaterial to our consolidated financial statements.

In March 2006, the FASB issued an exposure draft on accounting for pension and postretirement medical benefits. The final standard for the first phase of this project is expected to be issued in the third quarter of 2006, with implementation required for years ending after December 15, 2006. Based on the exposure draft, we could be required to record a balance sheet liability equal to the difference between our benefit obligations and plan assets. If this requirement had been in place at December 31, 2005, we would have been required to record unrecognized losses of \$124.8 million and \$78.8 million for pension and postretirement benefits, respectively, on our consolidated balance sheet as accumulated other comprehensive loss.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Derivatives and Risk Management Activities - We engage in wholesale energy marketing, retail marketing, trading, and risk management activities. We account for derivative instruments utilized in connection with these activities and services under the fair value basis of accounting in accordance with Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (Statement 133), as amended.

Under Statement 133, entities are required to record derivative instruments at fair value. The fair value of derivative instruments is determined by commodity exchange prices, over-the-counter quotes, volatility, time value, counterparty credit and the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions. Refer to the table on page 52 for amounts in our portfolio at March 31, 2006, that were determined by prices actively quoted, prices provided by other external sources and prices derived from other sources. The majority of our portfolio's fair values are based on actual market prices. Transactions are also executed in markets for which market prices may exist but the market may be relatively inactive, thereby resulting in limited price transparency that requires management's subjectivity in estimating fair values.

Market value changes result in a change in the fair value of our derivative instruments. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it. If the derivative instrument does not qualify or is not designated as part of a hedging relationship, we account for changes in fair value of the derivative in earnings as they occur. Commodity price volatility may have a significant impact on the gain or loss in any given period. For more information on fair value sensitivity and a discussion of the market risk of pricing changes, see Item 3, Quantitative and Qualitative Disclosures about Market Risk.

To minimize the risk of fluctuations in natural gas, natural gas liquids (NGLs) and condensate prices, we periodically enter into futures transactions and swaps in order to hedge anticipated purchases and sales of natural gas and condensate, fuel requirements and NGL inventories. Interest rate swaps are also used to manage interest rate risk. Under certain conditions, we designate these derivative instruments as a hedge of exposure to changes in fair values or cash flows. For hedges of exposure to changes in fair value, the gain or loss on the derivative instrument is recognized in earnings in the period of change together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. For hedges of exposure to changes in cash flow, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of other comprehensive income and is subsequently reclassified into earnings when the forecasted transaction affects earnings. Any ineffectiveness of designated hedges is reported in earnings in the period the ineffectiveness occurs.

Many of our purchase and sale agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and normal sales under Statement 133 and are therefore exempt from fair value accounting treatment.

Impairment of Goodwill and Long-Lived Assets - We assess our goodwill for impairment at least annually based on Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (Statement 142). An initial assessment is made by comparing the fair value of the operations with goodwill, as determined in accordance with Statement 142, to the book value of each reporting unit. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the operations with goodwill from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, we will record an impairment charge. At March 31, 2006, we had \$567.3 million of goodwill recorded on our balance sheet as shown below.

<i>(Thousands of Dollars)</i>	
Gathering and Processing	\$ 15,604
Natural Gas Liquids	173,945
Pipelines and Storage	24,141
Energy Services	10,255
Distribution	158,554
Northern Border Partners	184,843
Total goodwill	\$ 567,342

We assess our long-lived assets for impairment based on Statement 144. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

Examples of long-lived asset impairment indicators include:

- a significant decrease in the market price of a long-lived asset or asset group,
- a significant adverse change in the extent or manner in which a long-lived asset or asset group is being used or in its physical condition,
- a significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset or asset group, including an adverse action or assessment by a regulator that would exclude allowable costs from the rate-making process,
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset or asset group,
- a current-period operating cash flow loss, combined with a history of operating cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset or asset group, and
- a current expectation that, more likely than not, a long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

We do not currently anticipate any goodwill or asset impairments to occur within the next year, but if such events were to occur over the long-term, the impact could be significant to our financial condition and results of operations.

Pension and Postretirement Employee Benefits - We have a defined benefit pension plan covering substantially all full-time employees and a postretirement employee benefits plan covering most employees. Our actuarial consultant calculates the expense and liability related to these plans and uses statistical and other factors that attempt to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, age and employment periods. In determining the projected benefit obligations and the costs, assumptions can change from period to period and result in material changes in the costs and liabilities we recognize. For additional information, see Note J in our Annual Report on Form 10-K for the year ended December 31, 2005.

During 2005, we recorded net periodic benefit costs of \$13.0 million related to our defined benefit pension plans and \$27.4 million related to postretirement benefits. We estimate that in 2006 we will record net periodic benefit costs of \$21.9 million related to our defined benefit pension plan and \$25.9 million related to postretirement benefits. In determining our estimated expenses for 2006, our actuarial consultant assumed an 8.75 percent expected return on plan assets and a discount rate of 5.75 percent. A decrease in our expected return on plan assets to 8.50 percent would increase our 2006 estimated net periodic benefit

costs by approximately \$1.6 million for our defined benefit pension plan and would not have a significant impact on our postretirement benefit plan. A decrease in our assumed discount rate to 5.25 percent would increase our 2006 estimated net periodic benefit costs by approximately \$4.9 million for our defined benefit pension plan and \$1.6 million for our postretirement benefit plan. For 2006, we anticipate our total contributions to our defined benefit pension plan and postretirement benefit plan to be \$1.5 million and \$17.3 million, respectively, and our pay-as-you-go other postretirement benefit plan costs to be \$14.0 million. See Note 1 of Notes to Consolidated Financial Statements in this Form 10-Q.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal exposures and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated in accordance with Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies." We base our estimates on currently available facts and our estimates of the ultimate outcome or resolution. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings.

For further discussion of our accounting policies, see Note A of Notes to the Consolidated Financial Statements in this Form 10-Q.

FINANCIAL AND OPERATING RESULTS

Consolidated Operations

The following table sets forth certain selected consolidated financial information for the periods indicated.

Financial Results	Three Months Ended	
	March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Operating revenues, excluding energy trading revenues	\$ 3,910,952	\$ 2,697,848
Energy trading revenues, net	7,370	9,192
Cost of sales and fuel	3,343,173	2,336,643
Net margin	575,149	370,397
Operating costs	194,175	140,802
Depreciation, depletion and amortization	69,426	43,217
Operating income	\$ 311,548	\$ 186,378
Other income	\$ 12,555	\$ 5,298
Other expense	\$ 5,844	\$ 782
Minority interest in income of consolidated subsidiaries	\$ 45,497	\$ -
Discontinued operations, net of taxes:		
Income (loss) from operations of discontinued components, net of tax	\$ (239)	\$ 5,886

Operating Results - Net margin increased for the three months ended March 31, 2006, compared with the same period in 2005 primarily due to:

- the consolidation of our investment in Northern Border Partners as required by EITF 04-5,
- the effect of increased natural gas basis differentials on transportation contracts in our Energy Services segment,
- an increase in demand fees associated with our Energy Services segment's peaking and load following services,
- the effect of the natural gas liquids assets acquired from Koch in our Natural Gas Liquids segment and our Pipelines and Storage segment, and
- improved commodity prices in our Gathering and Processing segment.

These increases in net margin were slightly offset by a decrease in our Gathering and Processing segment due to the sale of our natural gas gathering and processing assets located in Texas during December 2005 and a decrease in our Distribution segment primarily due to warmer weather throughout our service areas.

Consolidated operating costs increased for the three-month period primarily due to our consolidation of our investment in Northern Border Partners as required by EITF 04-5, the costs related to the natural gas liquids assets acquired from Koch and increased employee benefit costs.

Depreciation, depletion and amortization increased for the three-month period primarily due to the consolidation of our investment in Northern Border Partners as required by EITF 04-5 and the costs associated with the natural gas liquids assets we acquired from Koch.

Minority interest expense primarily relates to the 97.3 percent of Northern Border Partners that we did not own and the 30 percent interest in Northern Border Pipeline which was not owned by Northern Border Partners as of March 31, 2006.

The following tables show the components of other income and other expense for the three months ended March 31, 2006 and 2005.

	Three Months Ended	
	March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Equity income	\$ 6,472	\$ 2,815
Cumulative effect of adoption of Statement 123R	1,721	-
Income from benefit plan investments	1,311	697
Other	3,051	104
Unrealized gain on investment	-	1,682
Other Income	\$ 12,555	\$ 5,298

	Three Months Ended	
	March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Acquisition expense	\$ 4,565	\$ 133
Other	1,279	649
Other Expense	\$ 5,844	\$ 782

More information regarding our results of operations is provided in the discussion of operating results for each of our segments.

Gathering and Processing

Overview - Our Gathering and Processing segment is engaged in the gathering and processing of natural gas and fractionation of NGLs primarily in Oklahoma and Kansas. Our operations include the gathering of natural gas production from crude oil and natural gas wells. Through gathering systems, these volumes are aggregated for removal of water vapor, solids and other contaminants and to extract NGLs in order to provide marketable natural gas, commonly referred to as residue gas. When the liquids are separated from the raw natural gas at the processing plants, the liquids are generally in the form of a mixed NGL stream. This mixed stream is generally shipped to fractionators, where by applying heat and pressure, each NGL component is separated into marketable NGL products such as ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively NGL products). These NGL products can then be stored, transported and marketed to a diverse customer base of end users.

Acquisition and Divestiture - The following acquisition and divestiture are discussed beginning on page 29.

- In December 2005, we sold our natural gas gathering and processing assets located in Texas. This sale included approximately 3,700 miles of pipe and six processing plants with a capacity of 0.2 Bcf/d. The impact of these assets on our Gathering and Processing segment's operating income for the three months ended March 31, 2005, was \$9.4 million.
- In July 2005, we acquired Koch Vesco Holdings, LLC, an entity which owns a 10.2 percent interest in VESCO. VESCO owns a gas processing complex near Venice, Louisiana. The gas processing complex suffered hurricane damage in August 2005 and was put back into production on a limited basis in March 2006.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating information for our Gathering and Processing segment for the periods indicated.

Financial Results	Three Months Ended March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Natural gas liquids and condensate sales	\$ 114,396	\$ 149,481
Gas sales	190,003	181,800
Gathering, compression, dehydration and processing fees and other revenues	22,785	23,297
Cost of sales and fuel	264,768	283,447
Net margin	62,416	71,131
Operating costs	23,645	29,816
Depreciation, depletion and amortization	6,261	8,308
Operating income	\$ 32,510	\$ 33,007
Other income (expense), net	\$ 467	\$ (69)

Operating Information	Three Months Ended March 31,	
	2006	2005
Total gas gathered (<i>MMMBtu/d</i>)	880	1,110
Total gas processed (<i>MMMBtu/d</i>)	830	1,097
Natural gas liquids sales (<i>MBbls/d</i>)	33	49
Natural gas liquids produced (<i>MBbls/d</i>)	43	61
Gas sales (<i>MMMBtu/d</i>)	265	340
Capital expenditures (<i>Thousands of dollars</i>)	\$ 3,322	\$ 7,697
Realized composite NGL sales price (<i>\$/Gal</i>)	\$ 0.81	\$ 0.71
Realized condensate sales price (<i>\$/bbl</i>)	\$ 57.67	\$ 44.06
Realized natural gas sales price (<i>\$/MMBtu</i>)	\$ 7.96	\$ 5.94
Realized gross processing spread (<i>\$/MMBtu</i>)	\$ 3.43	\$ 2.94

	Three Months Ended March 31,	
	2006	2005
Keep whole:		
NGL shrink (<i>MMBtu/d</i>)	40,968	71,722
Plant fuel (<i>MMBtu/d</i>)	5,114	9,179
Condensate shrink (<i>MMBtu/d</i>)	3,403	5,280
Condensate sales (<i>Bbls/d</i>)	699	1,084
Percentage of total net margin	15%	17%
Percentage of Proceeds:		
Wellhead purchases (<i>MMBtu/d</i>)	129,813	195,639
NGL sales (<i>Bbls/d</i>)	4,423	6,625
Residue sales (<i>MMBtu/d</i>)	16,505	24,804
Condensate sales (<i>Bbls/d</i>)	1,093	1,642
Percentage of total net margin	65%	59%
Fee:		
Wellhead volumes (<i>MMBtu/d</i>)	879,677	1,109,878
Average rate (<i>\$/MMBtu</i>)	\$ 0.16	\$ 0.17
Percentage of total net margin	20%	24%

Operating Results - The financial and operating results shown above have been restated to reflect the transfer of the natural gas liquids marketing business that was previously included in our Gathering and Processing segment to our new Natural Gas Liquids segment.

The decrease in net margin for the three months ended March 31, 2006, compared with the same period for 2005, is primarily due to:

- a decrease of \$18.8 million resulting from the sale of natural gas gathering and processing assets located in Texas in December 2005, and
- a decrease of \$3.2 million due to reduced volumes processed driven by natural declines behind our system and contract terminations, partially offset by
- an increase of \$3.4 million related to our realized gross processing margins, net of hedges, on our keep whole contracts, and
- an increase of \$9.9 million due to higher natural gas and NGL prices on our percentage of proceeds (POP) contracts, net of hedges.

The gross processing spread for the first quarter of 2006 remains considerably higher than the previous five-year average of \$1.86. Based on current market conditions, the gross processing spread for the remainder of 2006 is expected to be above the previous five-year average.

Overall, the volume of gas gathered, processed and sold was down primarily as a result of the sale of our natural gas gathering and processing assets in Texas. The sale of our natural gas gathering and processing assets in Texas also resulted in decreased expenses for the three months ended March 2006, compared with the same period in 2005, and included:

- a \$7.2 million decrease in operating costs,
- a \$2.2 million decrease in depreciation, depletion and amortization, and
- a \$1.4 million decrease in capital expenditures.

The decrease in operating costs due to the sale of our natural gas gathering assets in Texas was partially offset by higher employee-related costs and utilities, while the decrease in capital expenditures for the three-month period was also impacted by the timing of compression expenditures.

Risk Management - We use derivative instruments to minimize the risks associated with price volatility. The realized financial impact of the derivative transactions is included in our operating income in the period that the physical transaction occurs.

The following table sets forth our hedging information for the remainder of 2006 for our Gathering and Processing segment.

Product	Nine Months Ending December 31, 2006	
	Volumes Hedged	Average Price
Percent of Proceeds:		
Condensate (a)	225 MBbls	\$52.00-60.00/Bbl
Natural gas (a)	1.4 Bcf	\$6.15-11.00/MMBtu

(a) - Hedged with NYMEX-based costless collars.

We continue to evaluate market conditions to take advantage of favorable pricing opportunities associated with our POP and keep whole quantities.

See Item 3, Quantitative and Qualitative Disclosures About Market Risk and Note D of the Notes to Consolidated Financial Statements in this Form 10-Q.

Natural Gas Liquids

Overview - Our Natural Gas Liquids segment gathers, stores, fractionates and treats raw NGLs produced from gas processing plants located in Oklahoma, Kansas and the Texas panhandle. We connect the NGL production basins in Oklahoma, Kansas and the Texas panhandle with the key NGL market centers in Conway, Kansas and Mont Belvieu, Texas.

Most natural gas produced at the wellhead contains a mixture of NGL components such as ethane, propane, iso-butane, normal butane and natural gasoline. Natural gas processing plants remove the NGLs from the natural gas stream to realize the higher economic value of the NGLs and to meet natural gas pipeline quality specifications, which limit NGL content in the natural gas stream due to liquid and Btu content. The NGLs that are separated from the natural gas stream at the natural gas processing plants remain in a mixed, raw form until they are gathered, primarily by pipeline, and delivered to our fractionators. A fractionator, by applying heat and pressure, separates each NGL component into marketable products, such as ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively, NGL products). These NGL products can then be stored or distributed to petrochemical, heating and motor gasoline manufacturers.

Acquisition - In July 2005, we acquired the natural gas liquids businesses from Koch which is discussed beginning on page 29.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating information for our Natural Gas Liquids segment for the periods indicated.

Financial Results	Three Months Ended	
	March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Natural gas liquids and condensate sales	\$ 779,829	\$ 312,242
Storage and fractionation revenues	39,594	5,243
Cost of sales	785,681	310,228
Net margin	33,742	7,257
Operating costs	11,224	2,415
Depreciation, depletion and amortization	5,399	30
Operating income	\$ 17,119	\$ 4,812
Other income (expense), net	\$ (131)	\$ (51)

Operating Information	Three Months Ended	
	March 31,	
	2006	2005
Natural gas liquids gathered <i>(MBbls/d)</i>	193	(a)
Natural gas liquids sales <i>(MBbls/d)</i>	208	98
Natural gas liquids fractionated <i>(MBbls/d)</i>	284	(a)
Capital expenditures <i>(Thousands of dollars)</i>	\$ 2,954	\$ 1,696

(a) - No data available as the acquisition of these assets was completed July 1, 2005.

Operating Results - The results of operations for 2005 shown above are related to the natural gas liquids marketing business that was previously included in our Gathering and Processing segment. The increases for the three-month period are primarily related to the natural gas liquids assets acquired in July 2005. The increase associated with our acquisition for the three-month period includes:

- an increase in net margin of \$28.2 million,
- an increase in operating costs of \$8.9 million, and
- an increase in depreciation, depletion and amortization of \$5.3 million.

The net margin increase for the three-month period was offset by \$1.8 million in lower NGL marketing margins related to our legacy operations, driven primarily by lower marketing fees and decreased sales volumes related to our natural gas gathering and processing assets in Texas which were sold in December 2005.

Pipelines and Storage

Overview - Our Pipelines and Storage segment operates our intrastate natural gas transmission pipelines, natural gas storage and FERC regulated natural gas liquids gathering and distribution pipelines and nonprocessable natural gas gathering facilities. We also provide interstate natural gas transportation service under Section 311(a) of the Natural Gas Policy Act.

In Oklahoma, we have access to the major natural gas producing areas, allowing for natural gas and natural gas liquids to be moved throughout the state. We have access to the major natural gas producing area in south central Kansas. In Texas, we are connected to the major natural gas producing areas in the Texas panhandle and the Permian Basin, providing for natural gas to be moved to the Waha Hub, where other pipelines may be accessed for transportation east to the Houston Ship Channel market and west to the California market. Our regulated natural gas liquids gathering connections provide raw NGLs gathered in Oklahoma, Kansas and the Texas panhandle to be delivered primarily to our affiliate fractionation facilities in Medford, Oklahoma and to our natural gas liquids distribution pipelines, which allows for access to two of the main NGL market centers in Conway, Kansas and Mont Belvieu, Texas.

Acquisition and Divestiture - In July 2005, we acquired the FERC regulated assets that were part of our acquisition from Koch. See page 29 for discussion.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating information for our Pipelines and Storage segment for the periods indicated.

Financial Results	Three Months Ended	
	March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Transportation and gathering revenues	\$ 45,817	\$ 28,369
Storage revenues	12,143	10,593
Gas sales and other revenues	4,952	1,423
Cost of sales and fuel	10,791	10,285
Net margin	52,121	30,100
Operating costs	16,790	11,569
Depreciation, depletion and amortization	7,583	4,376
Operating income	\$ 27,748	\$ 14,155
Other income (expense), net	\$ 1,558	\$ 286

Operating Information	Three Months Ended	
	March 31,	
	2006	2005
Natural gas transported (<i>MMcf</i>)	132,475	131,330
Natural gas liquids transported (<i>MBbls/d</i>)	193	(a)
Natural gas liquids gathered (<i>MBbls/d</i>)	55	(a)
Capital expenditures (<i>Thousands of dollars</i>)	\$ 3,576	\$ 1,727
Average natural gas price (<i>\$/MMBtu</i>) (mid-continent region)	\$ 7.23	\$ 5.71

(a) - No data available as the acquisition of these assets was completed July 1, 2005.

Operating results - Net margin increased for the three months ended March 31, 2006, compared with the same period in 2005, primarily due to:

- an increase of \$14.1 million for the three-month period related to net revenues on natural gas liquids gathering and distribution pipelines acquired from Koch in July 2005,
- an increase of \$6.1 million in transport revenues resulting from increased volumes in our commodity-based short-term business, improved fuel position and higher commodity prices,
- an increase of \$1.3 million in storage revenues as a result of new and renegotiated contracts, and
- an increase of \$1.0 million related to net margin on equity natural gas inventory sales.

Operating costs increased \$5.2 million for the three-month period, primarily related to \$4.6 million for operating the recently acquired natural gas liquids pipelines, with the balance being driven by higher regulatory compliance costs and employee costs.

The recently acquired natural gas liquids pipelines also accounted for most of the increase in depreciation, depletion and amortization for the three-month period.

Energy Services

Overview - Our Energy Services segment's primary focus is to create value for our customers by delivering physical natural gas products and risk management services through our network of contracted transportation and storage capacity and natural gas supply. These services include meeting our customers' baseload, swing and peaking natural gas commodity requirements on a year-round basis. To provide these bundled services, we lease storage and transportation capacity. Our total storage capacity under lease is 86 Bcf, with maximum withdrawal capability of 2.3 Bcf per day and maximum injection capability of 1.6 Bcf per day. Our current transportation capacity is 2.0 Bcf per day. The contracted storage and transportation capacity connects the major supply and demand centers throughout the United States. With these contracted assets, our ongoing business strategies include identifying, developing and delivering specialized services and products for premium value to our customers, which are primarily local distribution companies (LDCs), electric utilities, and commercial and industrial end users. Also, our storage and transportation capacity allows us opportunities to optimize these positions through our application of market knowledge and risk management skills. We also provide risk management services to our customers.

Due to seasonality of natural gas consumption, earnings are normally higher during the winter months than the summer months. Our Energy Services segment's margins are subject to fluctuations during the year primarily due to the impact certain seasonal factors have on sales volumes and the price of natural gas and crude oil. Natural gas sales volumes are typically higher in the winter heating months than in the summer months, reflecting increased demand due to greater heating requirements and, typically, higher natural gas prices that occur during the winter heating months. During periods of high natural gas demand, we utilize storage capacity to supplement natural gas supply volumes to meet peak day demand obligations or market needs.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating information for our Energy Services segment for the periods indicated. In the third quarter of 2005, we made the decision to sell our Spring Creek power plant, located in central Oklahoma, and exit the power generation business. These assets were held for sale at March 31, 2006, and, accordingly, this component of our business is accounted for as discontinued operations, in accordance with Statement 144. The discontinued operations are excluded from the financial and operating results below. For additional information, see discussion of discontinued operations on page 45.

Financial Results	Three Months Ended	
	March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Energy and power revenues	\$ 2,307,730	\$ 1,742,058
Energy trading revenues, net	7,370	9,192
Other revenues	115	206
Cost of sales and fuel	2,212,061	1,690,261
Net margin	103,154	61,195
Operating costs	9,260	8,044
Depreciation, depletion and amortization	575	402
Operating income	\$ 93,319	\$ 52,749
Other income (expense), net	\$ (2,942)	\$ (1,889)

Operating Information	Three Months Ended	
	March 31,	
	2006	2005
Natural gas marketed (<i>Bcf</i>)	310	325
Natural gas gross margin (<i>\$/Mcf</i>)	\$ 0.28	\$ 0.15
Physically settled volumes (<i>Bcf</i>)	602	625
Capital expenditures (<i>Thousands of dollars</i>)	\$ -	\$ 27

Operating Results - Net margin increased for the three months ended March 31, 2006, compared with the same period in 2005, primarily due to:

- a net increase of \$28.2 million in transportation margins, net of hedging activities, due to improved natural gas basis differentials between the mid-continent and gulf coast regions,

- a net increase of \$9.5 million in storage margins primarily due to an increase in demand fees associated with peaking and load following services, and
- an increase of \$4.1 million in our natural gas trading operations primarily due to favorable natural gas basis spread movements, partially offset by,
- a decrease of \$0.5 million related to power margins associated with a tolling transaction that expired December 31, 2005, which allowed us to sell steam and power generated in the Electric Reliability Council of Texas (ERCOT) market.

Operating costs increased \$1.2 million for the three-month period primarily due to increased employee-related costs.

Natural gas volumes marketed decreased for the three-month period in 2006 compared with 2005, primarily due to record-setting warmer weather during January 2006 in the majority of our territory. The warmer weather resulted in decreased storage withdrawals.

Our natural gas in storage at March 31, 2006, was 42.3 Bcf compared with 40.2 Bcf at March 31, 2005. At March 31, 2006, our total natural gas storage capacity under lease was 86 Bcf compared with 87 Bcf at March 31, 2005.

For derivative instruments considered “held for trading purposes” that result in physical delivery, the indicators in EITF Issue No. 02-3, “Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities” are used to determine the proper treatment. These activities and all financially settled derivative contracts are reported on a net basis.

For derivative instruments that are not considered “held for trading purposes” and result in physical delivery, the indicators in EITF 03-11, “Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not ‘Held for Trading’ as Defined in EITF Issue No. 02-3” (EITF 03-11) and EITF Issue No. 99-19, “Reporting Revenue Gross as a Principal versus Net as an Agent” (EITF 99-19) are used to determine the proper treatment. We account for the realized revenues and purchase costs of these contracts that result in physical delivery on a gross basis. We apply the indicators in EITF 99-19 to determine the appropriate accounting treatment for non-derivative contracts that result in physical delivery. Derivatives that qualify for the normal purchase or sale exception as defined in Statement 133 are also reported on a gross basis.

The following table shows margins by activity.

	Three Months Ended	
	March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Marketing and storage, gross	\$ 135,068	\$ 91,487
Less: Storage and transportation costs	(49,259)	(43,302)
Marketing and storage, net	85,809	48,185
Retail marketing	5,449	5,210
Financial trading	11,896	7,800
Net margin	\$ 103,154	\$ 61,195

Marketing and storage activities, net, primarily includes physical marketing, purchases and sales, firm storage and transportation capacity, including the impact of cash flow and fair value hedges and other derivative instruments used to manage our risk associated with these activities. The combination of owning supply, controlling strategic assets and risk management services allows us to provide commodity-diverse products and services to our customers such as peaking and load following services. Retail marketing includes revenues from providing physical marketing and supply services to residential and small commercial and industrial customers. Financial trading revenues include activities that are generally executed using financially settled derivatives. These activities are normally short-term in nature, with a focus of capturing short-term price volatility.

Distribution

Overview - Our Distribution segment provides natural gas distribution services to over two million customers in Oklahoma, Kansas and Texas through Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. We serve residential, commercial, industrial and transportation customers in all three states. In addition, our distribution services in Oklahoma and Kansas serve wholesale customers and in Texas serve public authority customers.

Selected Financial Information - The following table sets forth certain selected financial information for our Distribution segment for the periods indicated.

Financial Results	Three Months Ended	
	March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Gas sales	\$ 750,772	\$ 742,305
Transportation revenues	26,794	28,372
Cost of gas	591,802	576,910
Gross margin	185,764	193,767
Other revenues	10,118	7,453
Net margin	195,882	201,220
Operating costs	90,793	90,628
Depreciation, depletion and amortization	28,186	29,989
Operating income	\$ 76,903	\$ 80,603
Other income (expense), net	\$ 1,107	\$ (193)

Operating Results - Net margin decreased by \$5.3 million for the three months ended March 31, 2006, compared with the same period in 2005, primarily due to:

- an increase of \$14.9 million primarily due to the implementation of new rate schedules in Oklahoma,
- a decrease of \$12.2 million due to expiring riders and lowered volumetric rider collections in Oklahoma, and
- a decrease of \$6.7 million in customer sales due to warmer weather in our entire service territory.

Total volumes delivered declined seven percent for the three-month period as a result of warmer weather, while operating income declined five percent. The impact of warmer than normal weather in the three-month period was moderated by approved weather-protection mechanisms and by the implementation of a new two-tier rate structure in Oklahoma. The new Oklahoma rate structure reduces volumetric sensitivity while providing more consistent earnings and cash flow over time.

Operating costs increased for the three-month period primarily due to an increase of \$2.1 million in labor and employee benefit costs, which was offset by a \$1.9 million decrease in bad debt expense.

Depreciation, depletion and amortization decreased for the three-month period, primarily due to \$2.0 million in cathodic protection and service line amortization in Oklahoma from a limited issue rider which expired in 2005.

Selected Operating Data - The following tables set forth certain operating information for our Distribution segment for the periods indicated.

Operating Information	Three Months Ended	
	March 31,	
	2006	2005
Average number of customers	2,050,494	2,043,466
Customers per employee	712	688
Capital expenditures <i>(Thousands of dollars)</i>	\$ 36,675	\$ 27,686

Margin	Three Months Ended	
	March 31,	
	2006	2005
Gas sales	<i>(Thousands of dollars)</i>	
Residential	\$ 128,406	\$ 124,520
Commercial	31,877	37,100
Industrial	858	1,207
Wholesale	870	1,580
Public Authority	819	988
Gross margin on gas sales	162,830	165,395
Transportation	22,934	28,372
Gross margin	\$ 185,764	\$ 193,767

Volumes (MMcf)	Three Months Ended	
	March 31,	
	2006	2005
Gas sales		
Residential	52,423	58,545
Commercial	15,307	18,078
Industrial	580	782
Wholesale	4,940	6,872
Public Authority	887	965
Total volumes sold	74,137	85,242
Transportation	69,707	69,172
Total volumes delivered	143,844	154,414

Residential, commercial and industrial volumes decreased for the three-month period due to warmer weather during the first quarter of 2006.

Wholesale sales represent contracted gas volumes that exceed the needs of our residential, commercial and industrial customer base and are available for sale to other parties. Wholesale volumes also decreased for the three months ended March 31, 2006, due to warmer weather.

Public authority natural gas volumes reflect volumes used by state agencies and school districts serviced by Texas Gas Service.

Capital Expenditures - Our capital expenditure program includes expenditures for extending service to new areas, modifying customer service lines, increasing system capabilities, general replacements and improvements. It is our practice to maintain and periodically upgrade facilities to assure safe, reliable and efficient operations. Our capital expenditure program included \$13.5 million and \$9.4 million for new business development for the three months ended March 31, 2006 and 2005, respectively.

Regulatory Initiatives

Kansas - In April 2006, Kansas Gas Service notified the KCC of our intent to file an application for a rate increase on May 15, 2006.

Texas - Texas Gas Service received regulatory approval to implement a \$1.6 million increase in its south Jefferson County service area and a \$0.8 million increase in its north Texas service area. Both increases were effective April 28, 2006.

On March 30, 2006, Texas Gas Service filed a Statement of Intent to increase rates in its Rio Grande Valley service area by approximately \$3.4 million. We expect the cities in the Rio Grande Valley service area to take action within 125 days from the date of filing.

General - Certain costs to be recovered through the ratemaking process have been recorded as regulatory assets in accordance with Statement 71. Should recovery cease due to regulatory actions, certain of these assets may no longer meet the criteria of Statement 71 and, accordingly, a write-off of regulatory assets and stranded costs may be required.

Northern Border Partners

Overview - Our Northern Border Partners segment is engaged in the gathering and processing of natural gas, fractionation of NGLs, and interstate natural gas transportation.

Natural gas is gathered from producers' wells and central delivery points in three producing basins:

- the Williston Basin, which spans portions of Montana, North Dakota and the Canadian province of Saskatchewan,
- the Powder River Basin of Wyoming, and
- the Wind River Basin of Wyoming.

The Williston Basin operations compress and transport raw natural gas to our processing facilities, where water and other contaminants are removed and valuable natural gas liquids are extracted. We fractionate the natural gas liquids into marketable NGL products, such as ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively, NGL products). These NGL products are then sold to refineries or local markets. We compress the remaining residue gas and deliver it to interstate natural gas pipelines. The Powder River Basin facilities gather coalbed methane gas, which we process, compress and deliver to trunk gathering systems for transport and delivery to interstate natural gas pipelines. The Wind River Basin facilities consist of a partnership interest in a trunk gathering system.

Northern Border Partners also transports natural gas along 2,320 miles of interstate pipelines with a design capacity of approximately 4.7 billion cubic feet per day. Northern Border Partners' transportation network provides pipeline access to the Midwestern United States primarily from natural gas reserves in the Western Canada Sedimentary Basin, which is located in the Canadian provinces of Alberta, British Columbia and Saskatchewan. At March 31, 2006, Northern Border Partners' interstate natural gas pipelines included a 70 percent interest in Northern Border Pipeline Company, 100 percent ownership interests in Midwestern Gas Transmission Company and Viking Gas Transmission Company, and a 33 1/3 percent interest in Guardian Pipeline.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating information for our Northern Border Partners segment for the periods indicated.

Financial Results	Three Months Ended	
	March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Interstate natural gas pipeline revenues	\$ 95,731	\$ 96,645
Natural gas gathering and processing revenues	73,556	57,573
Other revenues	1,625	6,161
Cost of sales	44,111	32,465
Net margin	126,801	127,914
Operating costs	41,730	42,984
Depreciation, depletion and amortization	21,294	21,392
Operating income	\$ 63,777	\$ 63,538
Other income (expense), net	\$ 6,591	\$ 4,995
Minority Interest	\$ 11,206	\$ 12,189

Operating Information (a)	Three Months Ended	
	March 31,	
	2006	2005
Interstate natural gas pipeline:		
Natural gas delivered (MMcf)	305,280	306,692
Natural gas average throughput (MMcf/d)	3,468	3,501
Natural gas gathering and processing:		
Natural gas gathered (MMcf/d)	1,095	1,049
Natural gas processed (MMcf/d)	65	60
Capital expenditures (Thousands of dollars)	\$ 17,806	\$ 9,846

(a) - Includes 100 percent of the volumes for joint venture investments.

Operating results - We began consolidating our investment in Northern Border Partners as of January 1, 2006, in accordance with EITF 04-5. We elected to use the prospective method, which results in our consolidated financial results and operating information including only first quarter 2006 data for this segment. Accordingly, the 2005 data provided above is for comparison purposes only. See Impact of New Accounting Standards on page 30 for additional information.

Net margin and operating income were relatively flat for the three months ended March 31, 2006, compared to the same period in 2005, resulting from the increased gathering and processing volume contribution from the Williston Basin offset by due diligence, legal and other expenses related to the transactions with ONEOK and TC PipeLines. See Acquisitions and Divestitures on page 29 for additional discussion of these transactions. Black Mesa Pipeline is not reported as a discontinued operation because we believe that the operation is likely to resume in the future. See the Other section below for discussion of Black Mesa Pipeline.

The income from our 2.7 percent ownership interest in Northern Border Partners is \$2.6 million and \$2.5 million, before income taxes, for the three months ended March 31, 2006 and 2005, respectively.

Risk Management - We use derivative instruments to minimize the risks associated with price volatility. The realized financial impact of the derivative transactions is included in our operating income in the period that the physical transaction occurs.

The following table sets forth our hedging information for the remainder of 2006 for our Northern Border Partners segment.

Product	Nine Months Ending December 31, 2006	
	Volumes Hedged	Average Price
Percent of Proceeds:		
Natural gas (a)	1.9 Bcf	\$7.87/MMBtu
Natural gas liquids (a)	372 MBbbls	\$43.81/Bbl

(a) - Hedged with fixed price swap.

Regulatory Initiative - The FERC regulates the rates and charges for transportation on our interstate natural gas pipelines. Interstate natural gas pipeline companies may not charge rates that have been determined to be unjust and unreasonable by the FERC. Generally, rates for interstate pipelines are based on the cost of service, including recovery of and a return on the pipeline's actual prudent historical cost investment. The rates, terms and conditions for service are found in each pipeline's FERC-approved tariff. Under its tariff, an interstate pipeline is allowed to charge for its services on the basis of stated transportation rates. Transportation rates are established periodically in FERC proceedings known as rate cases. The tariff also allows the interstate pipeline to provide services under negotiated and discounted rates.

On November 1, 2005, Northern Border Pipeline, a subsidiary of Northern Border Partners, filed a rate case with the FERC as required by the settlement provisions of its last rate case. The rate case filing proposes, among other things, a 7.8 percent increase to Northern Border Pipeline's revenue requirement; a change to its rate design approach, with a supply zone and market area utilizing a fixed rate and a dekatherm-mile rate, respectively; a compressor usage surcharge, primarily to recover costs related to powering electric compressors; and implementation of a short-term rate structure on a prospective basis. Also included in the filing is the continuation of the inclusion of income taxes in the calculation of Northern Border Pipeline's rates.

In December 2005, the FERC issued an order that identified issues that were raised in the proceeding, accepted the proposed rates but suspended their effectiveness until May 1, 2006, at which time the new rates will be collected subject to refund until final resolution of the rate case. The FERC also issued a procedural schedule, which set a hearing commencement date of October 4, 2006, with an initial decision scheduled for February 2007, unless a settlement of the issues is reached with the FERC and a majority of Northern Border Pipeline's customers. At this time, Northern Border Pipeline can give no assurance as to the outcome of any of these issues.

Other - On December 31, 2005, our Northern Border Partners segment's Black Mesa Pipeline was temporarily shut down due to the expiration of our coal slurry transportation contract. The Mohave Generating Station co-owners, the Hopi Tribe, the Navajo Nation, Peabody Western Coal Company and other interested parties continue to negotiate water and coal supply issues. Black Mesa Pipeline is working to resolve coal slurry transportation issues so that operations may resume in the future. If there are successful resolutions of all of these issues and the project receives a favorable Environmental Impact Statement, we believe our coal slurry pipeline will be reconstructed in late 2008 and 2009 for an anticipated in-service date during 2010. We anticipate that the capital expenditures for the Black Mesa Pipeline refurbishment project will be in the range of \$175 million to \$200 million,

which will be supported by revenue from a new transportation contract. We expect to incur temporary shut down and stand by costs, net of reimbursement, of approximately \$2 million to \$4 million in 2006. Negotiations continue with various parties that may result in the recovery of some of these standby costs. If these issues are not resolved and the Mohave Generating Station is permanently closed, we expect to incur pipeline removal and remediation costs of approximately \$1 million to \$2 million, net of salvage, and to take a non-cash impairment charge of approximately \$10 million related to goodwill and the remaining undepreciated cost of the pipeline. The costs associated with permanent shut down are pre-tax. Depending on how negotiations progress and in accordance with accounting rules, an impairment charge may be required prior to final resolution of the issues concerning Mohave Generating Station even though the project may ultimately proceed.

DISCONTINUED OPERATIONS

Overview - In September 2005, we completed the sale of our Production segment to TXOK Acquisition, Inc. for \$645 million, before adjustments, and recognized a pre-tax gain on the sale of approximately \$240.3 million. The gain reflects the cash received less adjustments, selling expenses and the net book value of the assets sold. The proceeds from the sale were used to reduce debt. Our Board of Directors had approved the potential sale in July 2005, which resulted in our Production segment being classified as held for sale beginning July 1, 2005.

Additionally, in the third quarter of 2005, we made the decision to sell our Spring Creek power plant and exit the power generation business. We entered into an agreement to sell our Spring Creek power plant to Westar for approximately \$53 million. The transaction requires FERC approval and is expected to be completed in 2006. The 300-megawatt gas-fired merchant power plant was built in 2001 to supply electrical power during peak periods using gas-powered turbine generators. The proceeds from this sale will be used to purchase other assets, repurchase ONEOK shares or retire debt.

These components of our business are accounted for as discontinued operations in accordance with Statement 144. Accordingly, amounts in our financial statements and related notes for all periods shown relating to our Production segment and our power generation business are reflected as discontinued operations. The sale of our Production segment and the pending sale of our power generation business are in line with our business strategy to sell assets when deemed less strategic or as other conditions warrant.

Selected Financial Information - The amounts of revenue, costs and income taxes reported in discontinued operations are as follows.

	Three Months Ended	
	March 31,	
	2006	2005
	<i>(Thousands of dollars)</i>	
Operating revenues	\$ 1,849	\$ 45,823
Cost of sales and fuel	1,118	16,655
Net margin	731	29,168
Operating costs	218	7,676
Depreciation, depletion and amortization	-	8,280
Operating income	513	13,212
Other income (expense), net	-	(5)
Interest expense	904	3,712
Income taxes	(152)	3,609
Income (loss) from operations of discontinued components, net	\$ (239)	\$ 5,886

LIQUIDITY AND CAPITAL RESOURCES

General - Part of our strategy is to grow through acquisitions that strengthen and complement our existing assets. We have relied primarily on operating cash flow, borrowings from commercial paper and credit agreements, and issuance of debt and equity in the capital markets for our liquidity and capital resource requirements. We expect to continue to use these sources for liquidity and capital resource needs on both a short- and long-term basis. We have no material guarantees of debt or other similar commitments to unaffiliated parties. During 2006 and 2005, our capital expenditures were financed through operating cash flows

and short- and long-term debt. Capital expenditures for the first three months of 2006 were \$65 million, compared with \$58 million for the same period in 2005, exclusive of acquisitions.

Financing - Financing is provided through our commercial paper program and long-term debt. We also have credit agreements, as discussed below, which are used as a back-up for the commercial paper program and short-term liquidity needs. Other options to obtain financing include, but are not limited to, issuance of equity, issuance of mandatory convertible debt securities, issuance of trust preferred securities by ONEOK Capital Trust I or ONEOK Capital Trust II, asset securitization and sale/leaseback of facilities.

The total amount of short-term borrowings authorized by the Board of Directors of ONEOK, Inc. is \$2.5 billion and each issuance by Northern Border Partners is approved by the Northern Border Partners Policy Committee. At March 31, 2006, ONEOK had \$507 million in commercial paper outstanding, \$128 million in letters of credit issued, and available cash of approximately \$18.0 million. At March 31, 2006, Northern Border Partners had \$231 million outstanding under the 2006 Partnership Credit Agreement at a weighted average interest rate of 5.4 percent and Northern Border Pipeline had \$7 million outstanding under the 2005 Pipeline Credit Agreement at a weighted average interest rate of 5.2 percent. As of March 31, 2006, ONEOK could have issued \$2.2 billion of additional debt under the most restrictive provisions contained in our various borrowing agreements. As of March 31, 2006, Northern Border Partners and Northern Border Pipeline could have issued, under the most restrictive provisions of their agreements, \$459 million and \$523 million, respectively.

Short-term Bridge Financing Agreement - On July 1, 2005, we borrowed \$1.0 billion under ONEOK's new short-term bridge financing agreement to assist in financing our acquisition of assets from Koch. See Note B for additional information about this acquisition. We funded the remaining acquisition cost through our commercial paper program. At December 31, 2005, we had lowered the commitment of outstanding indebtedness under the bridge financing agreement to \$900.0 million. We repaid \$200.0 million on February 3, 2006 and we repaid an additional \$403.0 million on February 16, 2006, from the settlement of our equity units. The remaining balance of \$297.0 million was repaid in March 2006.

Five-year Credit Agreement - In April 2006, we amended ONEOK's 2004 \$1.2 billion five-year credit agreement to accommodate the transaction with Northern Border Partners. This amendment included changes to the material adverse effect representation, the burdensome agreement representation and the covenant regarding maintenance of control of Northern Border Partners.

Northern Border Partners - In May 2005, Northern Border Pipeline entered into a \$175 million five-year credit agreement (2005 Pipeline Credit Agreement). In March 2006, Northern Border Partners amended and restated its \$500 million revolving credit agreement (2006 Partnership Credit Agreement) and increased the amount they can borrow under the agreement to \$750 million. Both of the revolving credit facilities permit Northern Border Partners and Northern Border Pipeline to choose the lender's base rate or the London Interbank Offered Rate (LIBOR) plus a spread (based on each of their long-term unsecured debt ratings) as the interest rate on their outstanding borrowings, specify the portion of the borrowings to be covered by specific interest rate options and specify the interest rate period. The 2005 Pipeline Credit Agreement and the 2006 Partnership Credit Agreement are to be used for capital expenditures, acquisitions, general business purposes and refinancing existing indebtedness.

In April 2006, Northern Border Partners entered into a \$1.1 billion 364-day credit agreement and borrowed \$1.05 billion to fund a portion of its purchase of certain of assets comprising our Gathering and Processing segment, Natural Gas Liquids segment, and Pipelines and Storage segment. Until May 6, 2006, Northern Border Partners can make one additional borrowing of up to \$50 million for purposes of making payments related to this transaction. The interest rate is based, at their election, on either (i) the higher of prime or one-half of one percent above the Federal Funds Rate, which is the rate that banks charge each other for the overnight borrowing of funds, or (ii) the Eurodollar rate plus a set number of basis points based on Northern Border Partners' current long-term unsecured debt ratings by Moody's Investor Services (Moody's) and Standard and Poor's Ratings Group (S&P). Northern Border Partners anticipates permanent financing of its acquisition to come from proceeds resulting from the future issuance of long-term debt.

General - ONEOK's five-year credit agreement, Northern Border Pipeline's 2005 Pipeline Credit Agreement, and Northern Border Partners' 2006 Partnership Credit Agreement and \$1.1 billion 364-day credit agreements contain customary affirmative and negative covenants, including covenants relating to liens, investments, fundamental changes in our business, changes in the nature of our business, transactions with affiliates, the use of proceeds and a covenant that prevents us from restricting our subsidiaries' ability to pay dividends. ONEOK's five-year credit agreement also has limitations on our debt-to-capital ratio and a limit on investments in master limited partnerships. The debt covenant calculations in ONEOK's five-year credit agreement exclude the debt of Northern Border Pipeline and Northern Border Partners, since their lenders have no recourse against ONEOK. Northern Border Pipeline's and Northern Border Partners' agreements also have limitations on the interest coverage ratio and

their leverage ratio. The Northern Border Partners' \$1.1 billion 364-day credit agreement also contains mandatory prepayment provisions upon the sale of assets or issuance of debt or equity by Northern Border Partners. At March 31, 2006, ONEOK, Northern Border Pipeline and Northern Border Partners were in compliance with all covenants.

Equity Units - On February 16, 2006, we successfully settled our 16.1 million equity units with 19.5 million shares of our common stock. Of this amount, 8.3 million shares were issued from treasury stock and approximately 11.2 million shares were newly issued. Holders of the equity units received 1.2119 shares of our common stock for each equity unit they owned. The number of shares that we issued for each stock purchase contract was determined based on our average closing price over the 20 trading day period ending on the third trading day prior to February 16, 2006. With the settlement, we received \$402.4 million in cash, which was used to pay down our short-term bridge financing agreement.

Capitalization Structure - The following table sets forth our capitalization structure for the periods indicated.

	March 31, 2006	December 31, 2005
Long-term debt	57%	53%
Equity	43%	47%
Debt (including Notes payable)	62%	67%
Equity	38%	33%

Northern Border Partners

Acquisitions and Divestitures - On April 6, 2006, we sold and transferred certain assets comprising our Gathering and Processing segment, Natural Gas Liquids segment, and Pipelines and Storage segment to Northern Border Partners for approximately \$3 billion in cash and Class B limited partner units in Northern Border Partners. We also purchased, through Northern Plains, from an affiliate of TransCanada its 17.5 percent general partner interest in Northern Border Partners for \$40 million, less \$10 million for expenses associated with the transfer of operating responsibility of Northern Border Pipeline to TransCanada for a net payment of \$30 million. This purchase results in us owning 100 percent of the two percent general partner interest in Northern Border Partners.

We received approximately \$1.35 billion in cash, subject to adjustment for certain working capital items, and approximately 36.5 million Class B limited partner units from Northern Border Partners. The Class B limited partner units and related general partner interest contribution were valued at approximately \$1.65 billion. This transfer of assets includes the natural gas liquids assets we purchased from Koch in July 2005 for \$1.35 billion. Following the completion of the transactions, we did not recognize a gain on the transactions, as the transfer of assets was accounted for at historical cost since these transactions were between affiliates under common control. Following the completion of the transactions, we own approximately 37.0 million common and Class B limited partner units and 100 percent of the two percent Northern Border Partners' general partner interest. Our overall interest in Northern Border Partners, including the two percent general partner interest, has increased to 45.7 percent.

In April 2006, our Northern Border Partners segment completed the sale of a 20 percent partnership interest in Northern Border Pipeline to TC PipeLines Intermediate Limited Partnership (TC PipeLines), an affiliate of TransCanada, for approximately \$297 million. We each now own a 50 percent interest in Northern Border Pipeline, with an affiliate of TransCanada becoming operator of the pipeline in April 2007. Following completion of the transactions, Northern Border Partners will no longer consolidate Northern Border Pipeline in their financial statements. Instead, their interest in Northern Border Pipeline will be accounted for as an investment under the equity method. This change will be retroactive to January 1, 2006.

The sale and transfer of certain assets comprising our Gathering and Processing segment, Pipelines and Storage segment, and Natural Gas Liquids segment will not affect our consolidated operating income on our consolidated statements of income or total assets on our consolidated balance sheets, under EITF 04-5, as we were already required to consolidate our investment in Northern Border Partners effective January 1, 2006. However, minority interest expense and net income will be affected. See Impact of New Accounting Standards on page 30 for additional discussion of EITF 04-5.

The limited partner units we received from Northern Border Partners were newly-created Class B units with the same distribution rights as the outstanding common units, but have limited voting rights and are subordinated to the common units with respect to payment of minimum quarterly distributions. Distributions on the Class B units will be prorated from the date of issuance. Northern Border Partners is required to hold a special election for holders of common units within 12 months of issuing the Class B units to approve the conversion of the Class B units into common units and to approve certain amendments to the partnership

agreement. The proposed amendments grant voting rights for common units held by the general partner if a vote is held to remove the general partner and require fair market value compensation for the general partner interest if the general partner is removed. If the common unit holders do not approve both the conversion and amendments within 12 months of the issuance of the Class B units, then the amount payable on such Class B units would increase to 115 percent of the distributions paid on the common units and the Class B distribution rights would continue to be subordinated in the manner described above unless and until the conversion described above has been approved. If the common unit holders vote to remove us or our affiliates as the general partner of Northern Border Partners at any time prior to the approval of the conversion and amendment described above, the amount payable on such Class B units would increase to 125 percent of the distributions payable with respect to the common units and the Class B unit distribution rights would continue to be subordinated in the manner described above unless and until the conversion described above has been approved.

In April 2006, our Northern Border Partners segment acquired the remaining 66 2/3 percent interest in Guardian Pipeline for approximately \$77 million, increasing its ownership interest to 100 percent. Northern Border Partners used borrowings from its credit facility to fund its acquisition of the additional interest in Guardian Pipeline. Following the completion of the transaction, Northern Border Partners will consolidate Guardian Pipeline in their financial statements. As of May 4, 2006, Guardian Pipeline had approximately \$155 million of senior notes outstanding. Prior to the transaction, Guardian Pipeline was accounted for by Northern Border Partners as an investment under the equity method.

Capital Projects - In May 2006, a subsidiary of Northern Border Partners entered into an agreement with a subsidiary of Williams to form a joint venture called Overland Pass Pipeline Company, LLC (Overland Pass Pipeline Company). Overland Pass Pipeline Company will build a 750-mile natural gas liquids pipeline from Opal, Wyoming to the mid-continent natural gas liquids market center in Conway, Kansas. The pipeline will be designed to transport 110,000 barrels per day of NGLs, which can be increased to 150,000 barrels per day with additional pump facilities. Northern Border Partners will initially own 99 percent of the joint venture, will manage the construction project and will operate the pipeline. Williams will have the option to increase its ownership to 50 percent and become operator within two years of the pipeline becoming operational. Construction of the pipeline is expected to begin in the summer of 2007, with start-up scheduled for early 2008. As part of a long-term agreement, Williams will dedicate its NGL production from two of its gas processing plants in Wyoming to the joint-venture company. Subsidiaries of Northern Border Partners will provide downstream fractionation and transportation services. The pipeline project is estimated to cost approximately \$450 million. In addition, Northern Border Partners plans to invest approximately \$160 million to expand its existing fractionation capabilities and the capacity of its natural gas liquids pipelines. Northern Border Partners' financing for both projects may include a combination of short- or long-term debt or equity. The project requires the approval of various state and regulatory authorities.

In February 2006, Guardian Pipeline announced that it signed precedent agreements with two major Wisconsin utility companies to expand its existing natural gas pipeline system in eastern Wisconsin. The proposed project will expand and extend the existing pipeline approximately 106 miles from its current terminus near Ixomia, Wisconsin to the Green Bay area, adding approximately 537 MMcf/d of capacity. Guardian Pipeline's capital costs for the project are estimated to range between \$220 million and \$240 million. Pending all necessary approvals, the target in-service date is November 2008.

Additionally, Northern Border Partners had \$28 million in long-term capital project obligations related to their construction of the Midwestern Gas Transmission Eastern Extension Project which will add 31 miles of natural gas pipeline with approximately 120 MMcf/d of transportation capacity. The proposed in-service date of November 2006 will likely be delayed. Midwestern Gas Transmission is a bi-directional system that interconnects with Tennessee Gas Transmission near Portland, Tennessee and several interstate pipelines near Joliet, Illinois.

Stock Repurchase Plan - A total of 7.5 million shares have been repurchased to date pursuant to a plan approved by our Board of Directors. The plan originally approved by our Board of Directors in January 2005, was extended in November 2005, to allow us to purchase up to a total of 15 million shares of our common stock on or before November 2007. Shares are repurchased from time to time in open market transactions or through privately negotiated transactions at our discretion, subject to market conditions and other factors. During the first quarter of 2006, we did not repurchase any shares of our common stock under this plan.

Credit Rating - ONEOK's credit ratings are currently a "Baa2" (Stable) by Moody's and a "BBB" (CreditWatch with negative implications) by S&P. Northern Border Partners' credit ratings are currently a "Baa2" (Stable) by Moody's, a "BBB" (Credit Watch with negative implications) by S&P, and a "BBB+" by Fitch Ratings. Our credit ratings may be affected by a material change in our financial ratios or a material adverse event affecting our business. The most common criteria for assessment of our credit ratings are the debt-to-capital ratio, business risk profile, pretax and after-tax interest coverage, and liquidity. If our credit ratings were downgraded, the interest rates on our commercial paper borrowings would increase, resulting in an increase in our cost to borrow funds, and we could potentially lose access to the commercial paper market. In the event that we are unable to

borrow funds under our commercial paper program and there has not been a material adverse change in our business, we have access to a \$1.2 billion five-year credit agreement, which expires September 16, 2009.

Northern Border Partners' \$250 million and \$225 million long-term notes payable, due 2010 and 2011, respectively, contain provisions that require it to offer to repurchase the senior notes at par value if either the S&P or Moody's rate falls below investment grade and the investment grade rating is not reinstated for a period of 40 days.

Our Energy Services segment relies upon the investment grade rating of our senior unsecured long-term debt to satisfy credit requirements with most of our counterparties. If our credit ratings were to decline below investment grade, our ability to participate in energy marketing and trading activities could be significantly limited. Without an investment grade rating, we may be required to fund margin requirements with our counterparties with cash, letters of credit or other negotiable instruments. At March 31, 2006, the amount we could have been required to fund for the few counterparties with which we have a Credit Support Annex within our International Swaps and Derivatives Association Agreements is approximately \$114.2 million. A decline in our credit rating below investment grade may also significantly impact other business segments.

We have reviewed our commercial paper agreement, trust indentures, building leases, equipment leases, marketing, trading and risk contracts, and other various contracts which may be subject to rating triggers, and we do not have significant exposure. Rating triggers are defined as provisions that would create an automatic default or acceleration of indebtedness based on a change in our credit rating. Our credit agreements contain provisions that would cause the cost to borrow funds to increase if our credit rating is negatively adjusted. Northern Border Partners' and Northern Border Pipeline's credit agreements have similar provisions. The agreements also contain a default provision based on a material adverse change. An adverse rating change is not defined as a default or material adverse change.

Commodity Prices - We are subject to commodity price volatility. Significant fluctuations in commodity price in either physical or financial energy contracts may impact our overall liquidity due to the impact the commodity price change has on items such as the cost of NGLs and gas held in storage, increased margin requirements, collectibility of certain energy-related receivables and working capital. We believe that our current commercial paper program and debt capacity are adequate to meet our liquidity requirements associated with commodity price volatility.

Pension and Postretirement Benefit Plans - We calculate benefit obligations based upon generally accepted actuarial methodologies using the projected benefit obligation (PBO) for pension plans and the accumulated postretirement benefit obligation for other postretirement plans. We use a September 30 measurement date. The benefit obligations are the actuarial present value of all benefits attributed to employee service rendered. The PBO is measured using the pension benefit formula and assumptions as to future compensation levels. A plan's funded status is calculated as the difference between the benefit obligation and the fair value of plan assets. Our funding policy for the pension plans is to make annual contributions in accordance with regulations under the Internal Revenue Code and in accordance with generally accepted actuarial principles. Contributions made to our pension plan and our postretirement benefit plan in 2005 were \$1.5 million and \$3.1 million, respectively. For 2006, we anticipate our total contributions to our defined benefit pension plan and postretirement benefit plan to be \$1.5 million and \$17.3 million, respectively, and our pay-as-you-go other postretirement benefit plan costs to be \$14.0 million. We believe that we have adequate resources to fund our obligations under our pension and postretirement benefit plans.

CASH FLOW ANALYSIS

Our Consolidated Statements of Cash Flows combines cash flows from discontinued operations with cash flows from continuing operations within each category. Discontinued operations accounted for approximately \$1.2 million in operating cash flows for the three months ended March 31, 2005. Discontinued operations accounted for approximately \$(17.6) million in investing cash flows for the three months ended March 31, 2005, and did not account for any financing cash flows. The absence of cash flows from our discontinued operations is not expected to have a significant impact on our future cash flows.

Operating Cash Flows - Operating cash flows increased by \$292.7 million for the three months ended March 31, 2006, compared with the same period in 2005. The increase in operating cash flows was primarily the result of a net decrease in working capital of \$531.4 million in 2006, compared with a net decrease in working capital of \$346.2 million in 2005. These decreases primarily related to decreases in accounts receivable and inventory, partially offset by decreases in accounts payable. The decreases in accounts receivable and accounts payable primarily resulted from lower weighted average cost of natural gas in March 2006 compared with December 2005. Decreased gas in storage resulted from lower inventory levels at March 31 compared with December 31 due to withdrawals.

Investing Cash Flows - The change in other investments decreased for the three months ended March 31, 2006 compared with 2005 due primarily to the February 2005 exchange of 1.5 million Magnum Hunter Resources (MHR) stock purchase warrants with an exercise price of \$15 per share for 1.5 million shares of MHR common stock.

Financing Cash Flows - During the three months ended March 31, 2006, we repaid the remaining \$900 million under our short-term bridge financing agreement, which was used to initially finance our acquisition of assets from Koch. We also paid down \$134.5 million in commercial paper during the first quarter of 2006.

The first quarter of 2006 includes \$50.9 million in distributions to minority interests, which primarily resulted from our consolidation of Northern Border Partners in accordance with EITF 04-5 as of January 1, 2006.

On March 1, 2005, we had \$335 million of long-term debt mature. We funded this payment with working capital and the issuance of commercial paper in the short-term market.

During the first quarter of 2005, we paid \$63.6 million to repurchase approximately 2.1 million shares of our stock pursuant to a plan approved by our Board of Directors in 2005. This plan allows us to repurchase up to a total of 15 million shares of our common stock on or before November 17, 2007.

During the first quarter of 2005, we terminated \$400 million of our interest rate swap agreements and paid a net amount of \$19.4 million, which included \$20.2 million for the present value of future payments at the time of termination, less \$0.8 million for interest rate savings through the termination of the swaps. The \$20.2 million payment has been recorded as a reduction in long-term debt and will be recognized in the income statement over the term of the debt instruments originally hedged.

FORWARD-LOOKING STATEMENTS AND RISK FACTORS

Some of the statements contained and incorporated in this Report on Form 10-Q are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. The forward-looking statements relate to: anticipated financial performance; management's plans and objectives for future operations; business prospects; outcome of regulatory and legal proceedings; market conditions and other matters. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements in certain circumstances. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Report on Form 10-Q identified by words such as "anticipate," "estimate," "expect," "forecast," "intend," "believe," "projection" or "goal."

You should not place undue reliance on forward-looking statements. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- actions by rating agencies concerning the credit ratings of ONEOK and Northern Border Partners;
- the effects of weather and other natural phenomena on our operations, including energy sales and prices and demand for pipeline capacity;
- competition from other U.S. and Canadian energy suppliers and transporters as well as alternative forms of energy;
- the capital intensive nature of our businesses;
- the profitability of assets or businesses acquired by us;
- risks of marketing, trading and hedging activities as a result of changes in energy prices or the financial condition of our counterparties;
- economic climate and growth in the geographic areas in which we do business;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- the timing and extent of changes in commodity prices for natural gas, NGLs, electricity and crude oil;
- the effects of changes in governmental policies and regulatory actions, including changes with respect to income taxes, environmental compliance, authorized rates or recovery of gas costs;
- the impact of recently issued and future accounting pronouncements and other changes in accounting policies;

- the possibility of future terrorist attacks or the possibility or occurrence of an outbreak of, or changes in, hostilities or changes in the political conditions in the Middle East and elsewhere;
- the risk of increased costs for insurance premiums, security or other items as a consequence of terrorist attacks;
- the impact of unforeseen changes in interest rates, equity markets, inflation rates, economic recession and other external factors over which we have no control, including the effect on pension expense and funding resulting from changes in stock and bond market returns;
- risks associated with pending or possible acquisitions and dispositions, including our ability to finance or integrate any such acquisitions and any regulatory delay or conditions imposed by regulatory bodies in connection with any such acquisitions and dispositions;
- the results of administrative proceedings and litigation, regulatory actions and receipt of expected regulatory clearances involving the OCC, KCC, Texas regulatory authorities or any other local, state or federal regulatory body, including the FERC;
- our ability to access capital at competitive rates or on terms acceptable to us;
- the risk of a significant slowdown in growth or decline in the U.S. economy or the risk of delay in growth recovery in the U.S. economy;
- risks associated with adequate supply to our gathering and processing, fractionation and pipeline facilities, including production declines which outpace new drilling;
- the risk that material weaknesses or significant deficiencies in our internal controls over financial reporting could emerge or that minor problems could become significant;
- the impact of the outcome of pending and future litigation;
- the possible loss of franchises or other adverse effects caused by the actions of municipalities;
- the impact of unsold pipeline capacity being greater or less than expected;
- the ability to market pipeline capacity on favorable terms, which is affected by:
 - future demand for and prices of natural gas;
 - competitive conditions in the overall natural gas and electricity markets;
 - availability of supplies of Canadian and United States natural gas;
 - availability of additional storage capacity and weather conditions; and
 - competitive developments by Canadian and U.S. natural gas transmission peers;
- orders by the FERC which are significantly different than our assumptions related to Northern Border Pipeline's November 2005 rate case;
- performance of contractual obligations by the customers and shippers;
- the ability to recover operating costs and amounts equivalent to income taxes, costs of property, plant and equipment and regulatory assets in our FERC regulated rates;
- timely receipt of required regulatory clearances for construction and operation of the Midwestern Gas Transmission Eastern Extension Project;
- our ability to acquire all necessary rights-of-way and obtain agreements for interconnects in a timely manner;
- our ability to promptly obtain all necessary materials and supplies required for construction;
- the composition and quality of the natural gas we gather and process in our plants;
- the efficiency of our plants in processing natural gas and extracting natural gas liquids;
- renewal of our coal slurry pipeline transportation contract under reasonable terms and our success in completing the necessary rebuilding of the coal slurry pipeline;
- the impact of potential impairment charges;
- developments in the December 2, 2001, filing by Enron of a voluntary petition for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code affecting our settled claims;
- the ability to control operating costs;
- the risk inherent in the use of information systems in our respective businesses, implementation of new software and hardware, and the impact on the timeliness of information for financial reporting;
- acts of nature, sabotage, terrorism or other similar acts causing damage to our facilities or our suppliers' or shippers' facilities; and
- factors listed in the reports we have filed and may file with the Securities and Exchange Commission, which are incorporated by reference.

Other factors and assumptions not identified above were also involved in the making of the forward-looking statements. The failure of those assumptions to be realized, as well as other factors, may also cause actual results to differ materially from those projected. We have no obligation and make no undertaking to update publicly or revise any forward-looking information.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our quantitative and qualitative disclosures about market risk are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2005.

COMMODITY PRICE RISK

Energy Services

The following table provides a detail of our Energy Services segment's maturity of derivatives based on injection and withdrawal periods from April through March. This maturity schedule is consistent with our business strategy. Executory storage and transportation contracts and their related hedges are not included in the following table.

Source of Fair Value (a)	Fair Value of Derivatives at March 31, 2006		
	Matures through March 2007	Matures through March 2010	Total Fair Value
	<i>(Thousands of dollars)</i>		
Prices actively quoted (b)	\$ (24,281)	\$ 1,716	\$ (22,565)
Prices provided by other external sources (c)	30,095	(938)	29,157
Prices derived from quotes, other external sources and other assumptions (d)	(7,652)	882	(6,770)
Total	\$ (1,838)	\$ 1,660	\$ (178)

- (a) Fair value is the marked-to-market component of forwards, swaps, and options, net of applicable reserves. These fair values are reflected as a component of assets and liabilities from energy marketing and risk management activities in the Consolidated Balance Sheets.
- (b) Values are derived from energy market price quotes from national commodity trading exchanges that primarily trade futures and option commodity contracts.
- (c) Values are obtained through energy commodity brokers or electronic trading platforms, whose primary service is to match willing buyers and sellers of energy commodities. Energy price information by location is readily available because of the large energy broker network.
- (d) Values derived in this category utilize market price information from the other two categories, as well as other assumptions for liquidity and credit.

Fair Value Component of Energy Marketing and Risk Management Assets and Liabilities

	<i>(Thousands of dollars)</i>
Net fair value of derivatives outstanding at December 31, 2005	\$ 30,336
Derivatives realized or otherwise settled during the period	(43,128)
Fair value of new derivatives when entered into during the period	(19,326)
Other changes in fair value	31,940
Net fair value of derivatives outstanding at March 31, 2006	\$ (178)

For further discussion of trading activities and assumptions used in our trading activities, see Accounting Treatment in Note D of the Notes to Consolidated Financial Statements included in this Form 10-Q.

Value-at-Risk (VAR) Disclosure of Market Risk

The potential impact on our future earnings, as measured by VAR, was \$19.3 million and \$17.2 million at March 31, 2006, and 2005, respectively. The following table details the average, high and low daily VAR calculations.

Value-at-Risk	Three Months Ended	
	March 31,	
	2006	2005
	<i>(Millions of dollars)</i>	
Average	\$ 28.8	\$ 13.7
High	\$ 48.9	\$ 27.1
Low	\$ 17.7	\$ 7.4

The variations in the VAR data are reflective of market volatility and changes in the portfolios during the year. The 2006 increase in VAR, compared with 2005, is primarily due to comparatively higher commodity prices and market volatility in 2006.

INTEREST RATE AND CURRENCY RISK

Interest Rate Risk

General - At March 31, 2006, the interest rate on approximately 84 percent of our long-term debt was fixed after considering the impact of interest rate swaps.

At March 31, 2006, a 100 basis point move in the LIBOR rate on all of our outstanding long-term debt would change annual interest expense by approximately \$7.3 million before taxes. This 100 basis point change assumes a parallel shift in the yield curve. If interest rates changed significantly, we would take actions to manage our exposure to the change. Since a specific action and the possible effects are uncertain, no change has been assumed.

Fair Value Hedges - In prior years, we terminated various interest rate swap agreements. The net savings from the termination of these swaps is being recognized in interest expense over the terms of the debt instruments originally hedged. Net interest expense savings for the first quarter of 2006 for all terminated swaps was \$3.1 million and the remaining net savings for all terminated swaps will be recognized over the following periods:

	Northern Border		Total
	ONEOK	Partners	
	<i>(Millions of dollars)</i>		
Remainder of 2006	\$ 5.1	\$ 2.4	\$ 7.5
2007	6.6	3.4	10.0
2008	6.6	3.6	10.2
2009	5.6	3.8	9.4
2010	5.5	4.0	9.5
Thereafter	15.3	0.8	16.1

Currently, \$490 million of fixed rate debt is swapped to floating. The floating rate debt is based on both the three- and six-month London InterBank Offered Rate (LIBOR), depending upon the swap. At March 31, 2006, we had a net liability of \$21.2 million to recognize the interest rate swaps at fair value. Long-term debt was decreased by \$21.2 million to recognize the change in fair value of the related hedged liability.

Total savings from the interest rate swaps and amortization of terminated swaps was \$2.9 million for the three months ended March 31, 2006. The swaps are expected to net the following savings for the remainder of the year:

- interest expense savings of \$7.5 million related to the amortization of the swap value at termination and
- up to \$2.4 million in interest expense from the existing \$490 million of swapped debt, based on LIBOR rates at March 31, 2006.

Total swap savings for 2006 are expected to be \$8.0 million compared to \$10.7 million for 2005.

Currency Rate Risk

With our Energy Services segment's Canadian operations, we are subject to currency exposure related to our firm transportation and storage contracts. Our objective with respect to currency risk is to reduce the exposure due to exchange-rate fluctuations. We use physical forward transactions, which result in an actual two-way flow of currency on the settlement date since we exchange U.S. dollars for Canadian dollars with another party. We have not designated these transactions for hedge accounting treatment; therefore, the gains and losses associated with the change in fair value are recorded in net margin. At March 31, 2006, our exposure to risk from currency translation was not material and there was no material currency translation gain or loss recorded.

ITEM 4. CONTROLS AND PROCEDURES

Status of Material Weakness - As previously disclosed in our Annual Report on Form 10-K, the Company identified a software error in February 2006 which impacted our accounting for hedging instruments. The impact of this error was corrected prior to the issuance of the 2005 consolidated financial statements. As a result of the error, management concluded a material weakness existed as of December 31, 2005. During the first quarter of 2006, an alternate process was implemented to manually review and revalue the hedging ineffectiveness calculated by the software. The results are then validated through additional analytical reviews and reconciliations of reports generated by the affected software. We will continue to rely on the additional manual controls described above until we implement a permanent automated solution. Management believes these additional controls have effectively remediated the material weakness.

Quarterly Evaluation of Disclosure Controls and Procedures - We have established disclosure controls and procedures to ensure that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Securities and Exchange Act of 1934, as amended (the Act), is recorded, processed, summarized and reported, within the time periods specified in the U.S. Securities and Exchange Commission's (SEC) rules and forms. Under the supervision and with the participation of senior management, including our Chairman and Chief Executive Officer (Principal Executive Officer) and our Chief Financial Officer (Principal Financial Officer), we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Act. Based on this evaluation, our Principal Executive Officer and our Principal Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2006, in ensuring the timely disclosure of required information in our periodic SEC filings.

Changes in Internal Controls Over Financial Reporting - We have not made any changes in our internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Act) during the quarter ended March 31, 2006, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, except for those controls described in the above discussion of the Company's remediation efforts pertaining to the material weakness and in the next paragraph.

In July 2005, we completed our acquisition of the Natural Gas Liquids segment as more fully described in Note B in the Notes to our Consolidated Financial Statements included in Part I of this report. As part of our ongoing integration activities, we are in the process of developing and incorporating controls and procedures related to these assets into our internal controls over financial reporting. Until such controls are more fully developed, we have implemented and are relying on compensating controls and have performed extensive reviews of our reported results. As with any acquisition, there are inherent risks in the timing, development and implementation of internal controls that could negatively impact us; however, we do not believe they will have a material impact on our financial statements.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

J.P. Morgan Trust Company v. ONEOK, Inc., et al., originally filed in the District Court of Wyandotte County (Case No. 05-CV-1232), removed to the United States District Court for the District of Kansas (Case No. 05-CV-1331), transferred to MDL-1566 in the United States District Court for the District of Nevada (Case No. 05-CV-1331). On April 24, 2006, the Court denied the Motion to Remand filed by the plaintiff. The case has been transferred to the MDL 1566 proceeding.

Notice of Rate Change of Northern Border Pipeline Company, Federal Energy Regulatory Commission, Docket No. RP06-72-000. On November 1, 2005, Northern Border Pipeline Company (“Northern Border Pipeline”) filed a rate case with the FERC as required by the provisions of a settlement reached by Northern Border Pipeline in its 1999 rate case. The rate case filing proposes a 7.8 percent increase to Northern Border Pipeline’s revenue requirement; a change to its rate design approach with a supply zone and market area utilizing a fixed rate per dekatherm and a dekatherm-mile rate, respectively; a compressor usage surcharge primarily to recover costs related to powering electric compressors; and the implementation of a short-term rate structure on a prospective basis. In December 2005, the FERC issued an order that identified issues raised in the proceeding and accepted the proposed rates but suspended their effectiveness until May 1, 2006, at which time the new rates will be collected subject to refund until final resolution of the rate case. The FERC also issued a procedural schedule which set a hearing commencement date of October 4, 2006, with an initial decision scheduled for February 2007, unless a settlement of the issues is reached with the FERC and a majority of Northern Border Pipeline’s customers.

ITEM 1A. RISK FACTORS

Our investors should consider the risks set forth in Item 1A, Risk Factors of our Annual Report on Form 10-K, for the year ending December 31, 2005, and the following risks that could affect us and our business. Although we have tried to discuss key factors, please be aware that other risks may prove to be important in the future. New risks may emerge at any time and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the following discussion of risks and the other information included or incorporated by reference in this Quarterly Report on Form 10-Q, including Forward-Looking Information, which is included in Item 2, Management’s Discussion and Analysis of Financial Condition and Results of Operations.

Our Northern Border Partners segment may not be able to successfully integrate the operations of our Gathering and Processing segment, our Pipelines and Storage segment and our Natural Gas Liquids segment with their current operations.

The integration of our Gathering and Processing segment, our Pipelines and Storage segment and our Natural Gas Liquids segment with Northern Border Partners’ current operations will be a complex, time-consuming and costly process. Failure to timely and successfully integrate our Gathering and Processing segment, our Pipelines and Storage segment and our Natural Gas Liquids segment may have a material adverse effect on our business, financial condition and results of operations. The difficulties of integrating our Gathering and Processing segment, our Pipelines and Storage segment and our Natural Gas Liquids segment will present challenges to management including:

- operating a significantly larger combined company with operations in geographic areas in which they have not previously operated;
- managing relationships with new customers for whom they have not previously provided services;
- integrating personnel with diverse backgrounds and organizational cultures;
- experiencing operational interruptions or the loss of key employees, customers or suppliers;
- working through inefficiencies and complexities that may arise due to our Northern Border Partners segment’s unfamiliarity with the new operations and the businesses associated with them, including with their markets;
- assimilating the operations, technologies, services and products of our Gathering and Processing segment, our Pipelines and Storage segment and our Natural Gas Liquids segment into Northern Border Partners;
- assessing the internal controls and procedures for the combined entity that we are required to maintain under the Sarbanes-Oxley Act of 2002; and
- consolidating other corporate and administrative functions.

We will also be exposed to risks that are commonly associated with transactions similar to this acquisition, such as unanticipated liabilities and costs, some of which may be material, and diversion of management's attention. As a result, the anticipated benefits of the integration of our Gathering and Processing segment, our Pipelines and Storage segment and our Natural Gas Liquids segment into Northern Border Partners may not be fully realized, if at all.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

ISSUER PURCHASES OF EQUITY SECURITIES

The following table sets forth information relating to our purchases of equity securities during the three months ended March 31, 2006.

Period	Total Number of Shares (or Units) Purchased	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
January 1-31, 2006	9,392 (1) (2)	\$29.18	-	7,500,000
February 1-28, 2006	716 (1) (2)	\$31.47	-	7,500,000
March 1-31, 2006	37,241 (1) (2)	\$29.85	-	7,500,000
Total	47,349	\$29.74	-	7,500,000

(1) Includes shares withheld pursuant to attestation of ownership and deemed tendered to us in connection with the exercise of stock options under the ONEOK, Inc. Long-Term Incentive Plan, as follows :

9,349 shares for the period January 1-31, 2006

708 shares for the period February 1-28, 2006

37,227 shares for the period March 1-31, 2006

(2) Includes shares repurchased directly from employees, pursuant to our Employee Stock Award Program, as follows:

43 shares for the period January 1-31, 2006

8 shares for the period February 1-28, 2006

14 shares for the period March 1-31, 2006

EMPLOYEE STOCK AWARD PROGRAM

Under our Employee Stock Award Program, we issued, for no consideration, to all eligible employees (all full-time employees and employees on short-term disability) one share of our common stock when the per-share closing price of our common stock on the New York Stock Exchange (NYSE) was for the first time at or above \$26 per share, and we will issue, for no consideration, one additional share of our common stock to all eligible employees when the closing price on the NYSE is for the first time at or above each one dollar increment above \$26 per share. The total number of shares of our common stock available for issuance under this program is 100,000.

Through March 31, 2006, a total of 45,415 shares had been issued to employees under this program.

The issuance of shares under this program has not been registered under the Securities Act of 1933, as amended (1933 Act) in reliance upon Securities and Exchange Commission releases, including Release No. 6188, dated February 1, 1980, stating that there is no sale of the shares in the 1933 Act sense to employees under this type of program.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not Applicable.

ITEM 4. SUBMISSION OF MATTERS TO VOTE OF SECURITY HOLDERS

Not Applicable.

ITEM 5. OTHER INFORMATION

Not Applicable.

ITEM 6. EXHIBITS

The following exhibits are filed as part of this Quarterly Report on Form 10-Q:

<u>Exhibit No.</u>	<u>Exhibit Description</u>
12.1	Computation of Ratio of Earnings to Fixed Charges for the three months ended March 31, 2006 and 2005.
31.1	Certification of David L. Kyle pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Jim Kneale pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of David L. Kyle pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
32.2	Certification of Jim Kneale pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).

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.

ONEOK, Inc.
Registrant

Date: May 4, 2006

By: /s/ Jim Kneale
Jim Kneale
Executive Vice President -
Finance and Administration
and Chief Financial Officer
(Principal Financial Officer)