ONEOK INC /NEW/
Form 10-Q/A
November 14, 2002

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q/A

(Amendment No. 1)

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

FOR THE QUARTERLY PERIOD ENDED June 30, 2002

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	**73-1520922**
(State or other jurisdiction of incorporation of organization)	**(I.R.S. Employer Identification No.)**
100 West Fifth Street, Tulsa, OK	**74103**
(Address of principal executive offices)	**(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 x No ¨

Common stock, with par value of $0.01 60,408,566 shares outstanding at August 9, 2002.

Explanatory Statement:

The purpose of this Amendment No. 1 is to restate the Consolidated Statements of Cash Flows on p. 6 of the ONEOK, Inc. Form 10-Q for the quarter ended June 30, 2002 to correct mathematical errors related to the treatment of bank overdrafts in 2002, to add Note L to the consolidated financial statements discussing the restatement, and to modify the discussion of operating cash flows on p. 38 for the restatement. Except as amended as described above, the Consolidated Financial Statements of the Company being filed herewith (and included in the Company s Form 10-Q for the quarter ended June 30, 2002 as previously filed with the Securities and Exchange Commission) remain unchanged.

Part I FINANCIAL INFORMATION

Item 1. Financial Statements

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)	Three Months Ended June 30, **2002**	Three Months Ended June 30, 2001	Six Months Ended June 30, **2002**	Six Months Ended June 30, 2001
	(Thousands of Dollars, except per share amounts)			
Operating Revenues	**$ 1,171,444**	$ 1,402,399	**$ 2,637,102**	$ 4,359,323
Cost of gas	**916,525**	1,181,444	**2,074,611**	3,847,507
Net Revenues	**254,919**	220,955	**562,491**	511,816
Operating Expenses				
Operations and maintenance	**110,098**	96,179	**219,164**	190,974
Depreciation, depletion, and amortization	**44,976**	37,856	**85,212**	74,811
General taxes	**15,528**	14,978	**30,850**	31,043
Total Operating Expenses	**170,602**	149,013	**335,226**	296,828
Operating Income	**84,317**	71,942	**227,265**	214,988
Other income, net	**5,131**	566	**4,411**	3,865
Interest expense	**27,853**	36,249	**54,035**	73,784
Income taxes	**26,212**	12,651	**69,660**	54,451
Income before cumulative effect of a change in accounting principle	**35,383**	23,608	**107,981**	90,618
Cumulative effect of a change in accounting principle, net of tax (Note H)				(2,151)
Net Income	**35,383**	23,608	**107,981**	88,467
Preferred stock dividends	**9,275**	9,275	**18,550**	18,550
Income Available for Common Stock	**$ 26,108**	$ 14,333	**$ 89,431**	$ 69,917
Earnings Per Share of Common Stock *(Note D)*				
Basic	**$ 0.29**	$ 0.20	**$ 0.90**	$ 0.74
Diluted	**$ 0.29**	$ 0.20	**$ 0.89**	$ 0.74
Average Shares of Common Stock (Thousands)				
Basic	**99,877**	99,407	**99,808**	99,311
Diluted	**100,707**	99,733	**100,488**	99,665

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

(Unaudited)	**June 30, 2002**	December 31, 2001
	(Thousands of Dollars)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 43,778**	$ 28,229
Trade accounts and notes receivable, net	**561,753**	677,796
Materials and supplies	**17,897**	20,310
Gas in storage	**57,309**	82,694
Unrecovered purchased gas costs		45,098
Assets from price risk management activities	**798,610**	587,740
Deposits		41,781
Other current assets	**25,872**	78,321
Total Current Assets	**1,505,219**	1,561,969
Property, Plant and Equipment		
Marketing and Trading	**123,751**	122,172
Gathering and Processing	**1,065,447**	1,040,195
Transportation and Storage	**808,214**	792,641
Distribution	**2,035,353**	1,985,177
Production	**505,723**	482,404
Other	**91,681**	85,168
Total Property, Plant and Equipment	**4,630,169**	4,507,757
Accumulated depreciation, depletion, and amortization	**1,307,681**	1,234,789
Net Property, Plant and Equipment	**3,322,488**	3,272,968
Deferred Charges and Other Assets		
Regulatory assets, net (Note B)	**228,568**	232,520
Goodwill	**113,868**	113,868
Assets from price risk management activities	**359,781**	475,066
Investments and other	**176,207**	222,768
Total Deferred Charges and Other Assets	**878,424**	1,044,222
Total Assets	**$ 5,706,131**	$ 5,879,159

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

(Unaudited)	**June 30, 2002**	December 31, 2001
	(Thousands of Dollars)	
Liabilities and Shareholders Equity		
Current Liabilities		
Current maturities of long-term debt	**$ 10,000**	$ 250,000
Notes payable	**351,106**	599,106
Accounts payable	**435,940**	390,479
Accrued taxes	**13,957**	11,528
Accrued interest	**31,433**	31,954
Unrecovered purchased gas costs	**14,112**	
Customers deposits	**21,147**	21,697
Liabilities from price risk management activities	**506,303**	381,409
Other	**190,868**	132,244
Total Current Liabilities	**1,574,866**	1,818,417
Long-term Debt, excluding current maturities	**1,519,249**	1,498,012
Deferred Credits and Other Liabilities		
Deferred income taxes	**571,458**	499,432
Liabilities from price risk management activities	**374,141**	491,374
Lease obligation	**115,531**	122,011
Other deferred credits	**208,955**	184,623
Total Deferred Credits and Other Liabilities	**1,270,085**	1,297,440
Total Liabilities	**4,364,200**	4,613,869
Commitments and Contingencies (Note E)		
Shareholders Equity		
Convertible preferred stock, $0.01 par value:		
Series A authorized 20,000,000 shares; issued and outstanding 19,946,448 shares at June 30, 2002 and December 31, 2001	**199**	199
Common stock, $0.01 par value:		
authorized 300,000,000 shares; issued 63,438,441 shares with 60,352,331 and 60,002,218 shares outstanding at June 30, 2002 and December 31, 2001, respectively	**634**	634
Paid in capital (Note G)	**902,963**	902,269
Unearned compensation	**(3,716)**	(2,000)
Accumulated other comprehensive income (loss) (Note I)	**(747)**	(1,780)
Retained earnings	**486,381**	415,513
Treasury stock at cost: 3,036,534 shares at June 30, 2002; and 3,436,223 shares at December 31, 2001	**(43,783)**	(49,545)
Total Shareholders Equity	**1,341,931**	1,265,290
Total Liabilities and Shareholders Equity	**$ 5,706,131**	$ 5,879,159

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)	Six Months Ended June 30, **2002 (Restated)**	2001
	(Thousands of Dollars)	
Operating Activities		
Net income	**$ 107,981**	$ 88,467
Depreciation, depletion, and amortization	**85,212**	74,811
Gain on sale of assets	**(813)**	(1,120)
Gain on sale of equity investment	**(7,622)**	(758)
(Income) loss from equity investments	**553**	(6,209)
Deferred income taxes	**110,954**	16,582
Amortization of restricted stock	**1,058**	627
Allowance for doubtful accounts	**4,344**	13,839
Mark-to-market income	**(52,416)**	(27,609)
Changes in assets and liabilities:		
Accounts and notes receivable	**111,699**	942,459
Inventories	**27,798**	(4,743)
Unrecovered purchased gas costs	**59,210**	(80,237)
Deposits	**41,781**	37,170
Accounts payable and accrued liabilities	**75,576**	(652,369)
Price risk management assets and liabilities	**(35,031)**	(121,777)
Other assets and liabilities	**113,008**	(24,821)
Cash Provided by Operating Activities	**643,292**	254,312
Investing Activities		
Changes in other investments, net	**1,869**	1,504
Acquisitions	**(3,489)**	(15,337)
Capital expenditures	**(133,872)**	(173,990)
Proceeds from sale of property	**1,400**	7,911
Proceeds from sale of equity investment	**57,461**	7,425
Cash Used in Investing Activities	**(76,631)**	(172,487)
Financing Activities		
Payments of notes payable, net	**(248,000)**	(390,750)
Change in bank overdraft	**(28,757)**	(57,739)
Issuance of debt		400,000
Payment of debt	**(241,040)**	(2,455)
Issuance of common stock		5,169
Issuance of treasury stock, net	**3,798**	839
Dividends paid	**(37,113)**	(36,896)
Cash Used In Financing Activities	**(551,112)**	(81,832)
Change in Cash and Cash Equivalents	**15,549**	(7)
Cash and Cash Equivalents at Beginning of Period	**28,229**	249
Cash and Cash Equivalents at End of Period	**$ 43,778**	$ 242

See accompanying Notes to Consolidated Financial Statements.

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

A. Summary of Accounting Policies

Interim Reporting The accompanying unaudited consolidated financial statements of ONEOK, Inc. and its subsidiaries (the Company) have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial information. The interim consolidated financial statements reflect all adjustments, which, in the opinion of management, 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 the Company s business, the results of operations for the three and six months ended June 30, 2002, are not necessarily indicative of the results that may be expected for a twelve-month period. For further information, refer to the consolidated financial statements and footnotes thereto included in the Company s Annual Report on Form 10-K for the year ended December 31, 2001.

Goodwill On January 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets (Statement 142). Accordingly, the Company has discontinued the amortization of goodwill effective January 1, 2002. In accordance with the provisions of Statement 142, the Company has completed its analysis of goodwill for impairment and there was no impairment indicated. See Note J.

Reclassifications Certain amounts in the consolidated financial statements have been reclassified to conform to the 2002 presentation.

Critical Accounting Policies

Energy Trading and Risk Management Activities The Company engages in price risk management activities for both energy trading and non-trading purposes. The Company accounts for price risk management activities for its energy trading contracts in accordance with Emerging Issues Task Force Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities (EITF 98-10). EITF 98-10 requires entities involved in energy trading activities to account for energy trading contracts using mark-to-market accounting. Forwards, swaps, options, and energy transportation and storage contracts utilized for trading activities are reflected in the consolidated balance sheets at fair value as assets and liabilities resulting from price risk management activities. The fair value of these assets and liabilities is affected by the actual timing of settlements related to these contracts and current period changes resulting primarily from newly originated transactions and the impact of price movements. Changes in fair value are recognized in net revenues in the consolidated statements of income. Market prices used to determine the fair value of these assets and liabilities reflect management s best estimate considering various factors including closing exchange and over-the-counter quotations, time value and volatility underlying the commitments. Market prices are adjusted for the potential impact of liquidating the Company s position in an orderly manner over a reasonable period of time under currently existing market conditions.

The Marketing and Trading segment s gas in storage inventory is recorded at fair value and is included in current price risk management assets.

Regulation The Company s intrastate transmission pipelines and distribution operations are subject to the rate regulation and accounting requirements of the Oklahoma Corporation Commission (OCC), Kansas Corporation Commission (KCC) and Texas Railroad Commission (TRC). Certain other transportation activities of the Company are subject to regulation by the Federal Energy Regulatory Commission (FERC). Oklahoma Natural Gas (ONG) and Kansas Gas Service (KGS) 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). Allocation of costs and revenues to accounting periods for ratemaking and regulatory purposes may differ from allocations generally applied by non-regulated operations. Allocations of costs and revenues made by the Company to meet regulatory accounting requirements are considered to be in accordance with generally accepted accounting principles for regulated utilities.

During the ratemaking process, regulatory commissions may require a utility to defer recognition of certain costs to be recovered through rates over time as opposed to expensing such costs as incurred. This allows the utility to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. This causes certain expenses to be deferred as a regulatory asset and amortized to expense as they are recovered through rates. Total regulatory assets resulting from this deferral process were approximately $228.6 million and $232.5 million at June 30, 2002 and December 31, 2001, respectively. Should unbundling of services occur, certain of these assets may no longer meet the criteria for accounting for these assets in accordance with Statement 71 and, accordingly, a write-off of regulatory assets and stranded costs may be required. However, the Company does not anticipate that these costs, if any, will be significant. See Note B.

KGS was subject to a three-year rate moratorium, which was set to expire in November 2000. As a result of implementing a weather normalization mechanism in Kansas, KGS agreed to a two-year extension of the rate moratorium. The extended rate moratorium expires in November 2002 and KGS expects to file a rate case at that time. ONG is not subject to a rate moratorium.

Impairment of Long-Lived Assets The Company recognizes the impairment of a long-lived asset when indicators of impairment are present and the undiscounted cash flow is not sufficient to recover the carrying amount of these assets. The impairment loss is measured by comparing the fair value of the asset to its carrying amount. Fair values are based on discounted future cash flows or information provided by sales and purchases of similar assets.

B. Regulatory Assets

The following table is a summary of the Company s regulatory assets, net of amortization, for the periods indicated.

	June 30, 2002	December 31, 2001
	(Thousands of Dollars)	
Recoupable take-or-pay	**$ 72,588**	$ 75,336
Pension costs	**9,033**	11,124
Postretirement costs other than pension	**59,976**	60,170
Transition costs	**21,307**	21,598
Reacquired debt costs	**21,925**	22,351
Income taxes	**26,754**	28,365
Weather normalization	**9,717**	7,984
Line replacements	**2,392**	94
Other	**4,876**	5,498
Regulatory assets, net	**$ 228,568**	$ 232,520

C. Supplemental Cash Flow Information

The following table sets forth supplemental information with respect to the Company s cash flows for the periods indicated.

	Six Months Ended June 30, **2002**	2001
	(Thousands of Dollars)	
Cash paid during the period		
Interest (including amounts capitalized)	**$ 54,557**	$ 64,024
Income taxes	**$ 8,527**	$ 12,666
Income tax refund received	**$ 61,058**	$
Noncash transactions		
Dividends on restricted stock	**$ 116**	$ 96
Treasury stock transferred to compensation plans	**$ 25**	$ 131
Issuance of restricted stock, net	**$ 2,658**	$ 1,984
Acquisitions		
Property, plant and equipment	**$ 3,489**	$ 837
Goodwill	**$**	$ 14,500

D. Earnings Per Share Information

The Company computes its earnings per common share (EPS) in accordance with a pronouncement of the Financial Accounting Standards Board s Staff at the Emerging Issues Task Force meeting in April 2001, codified as EITF Topic No. D-95 (Topic D-95). In accordance with Topic D-95, the dilutive effect of the Company s Series A Convertible Preferred Stock is considered in the computation of basic EPS utilizing the if-converted method. Under the Company s if-converted method, the dilutive effect of the Company s Series A Convertible Preferred Stock on EPS cannot be less than the amount that would result from the application of the two-class method of computing EPS. The two-class method is an earnings allocation formula that determines EPS for the Company s common stock and its participating Series A Convertible Preferred Stock according to dividends declared and participating rights in the undistributed earnings. The Company s Series A Convertible Preferred Stock is a participating instrument with the Company s common stock with respect to the payment of dividends. For all periods presented, the two-class method resulted in additional dilution. Accordingly, EPS for such periods reflects this further dilution.

The following is a reconciliation of the basic and diluted EPS computations for the periods indicated.

	Three Months Ended June 30, 2002		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS			
Income available for common stock	**$ 26,108**	**59,985**	
Convertible preferred stock	**9,275**	**39,892**	
Income available for common stock and assumed conversion of preferred stock	**35,383**	**99,877**	**$ 0.35**
Further dilution from applying the two-class method			**(0.06)**
Basic earnings per share			**$ 0.29**
Effect of Other Dilutive Securities			
Options and other dilutive securities		**830**	
Diluted EPS			
Income available for common stock and assumed exercise of stock options	**$ 35,383**	**100,707**	**$ 0.35**
Further dilution from applying the two-class method			**(0.06)**
Diluted earnings per share			**$ 0.29**

	Three Months Ended June 30, 2001		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS			
Income available for common stock	$ 14,333	59,515	
Convertible preferred stock	9,275	39,892	
Income available for common stock and assumed conversion of preferred stock	23,608	99,407	$ 0.24
Further dilution from applying the two-class method			(0.04)
Basic earnings per share			$ 0.20
Effect of Other Dilutive Securities			
Options and other dilutive securities		326	
Diluted EPS			
Income available for common stock and assumed exercise of stock options	$ 23,608	99,733	$ 0.24
Further dilution from applying the two-class method			(0.04)
Diluted earnings per share			$ 0.20

	Six Months Ended June 30, 2002		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS			
Income available for common stock	$ 89,431	59,916	
Convertible preferred stock	18,550	39,892	
Income available for common stock and assumed conversion of preferred stock	107,981	99,808	$ 1.08
Further dilution from applying the two-class method			(0.18)
Basic earnings per share			$ 0.90
Effect of Other Dilutive Securities			
Options and other dilutive securities		680	
Diluted EPS			
Income available for common stock and assumed exercise of stock options	$ 107,981	100,488	$ 1.07
Further dilution from applying the two-class method			(0.18)
Diluted earnings per share			$ 0.89

	Six Months Ended June 30, 2001		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS			
Income available for common stock	$ 69,917	59,419	
Convertible preferred stock	18,550	39,892	
Income available for common stock and assumed conversion of preferred stock	88,467	99,311	$ 0.89
Further dilution from applying the two-class method			(0.15)
Basic earnings per share			$ 0.74
Effect of Other Dilutive Securities			
Options and other dilutive securities		354	
Diluted EPS			
Income available for common stock and assumed exercise of stock options	$ 88,467	99,665	$ 0.89
Further dilution from applying the two-class method			(0.15)
Diluted earnings per share			$ 0.74

There were 51,839 and 64,148 option shares excluded from the calculation of diluted EPS for the three months ended June 30, 2002 and 2001, respectively, since their inclusion would be antidilutive for each period. For the six months ended June 30, 2002 and 2001, there were 139,897 and 37,384 option shares, respectively, excluded from the calculation of diluted EPS since their inclusion would be antidilutive for each period.

The following is a reconciliation of the basic and diluted EPS computations before the cumulative effect of a change in accounting principle to net income for the periods indicated.

	Six Months Ended June 30,			
	Basic EPS		Diluted EPS	
	2002	2001	**2002**	2001
	(Per share amounts)			
Income available for common stockbefore cumulative effect of a change in accounting principle	**$ 0.90**	$ 0.76	**$ 0.89**	$ 0.76
Cumulative effect of a change in accounting principle, net of tax		(0.02)		(0.02)
Income available for common stock	**$ 0.90**	$ 0.74	**$ 0.89**	$ 0.74

E. Commitments and Contingencies

Enron Certain of the financial instruments discussed in the Company s Annual Report on Form 10-K for the year ended December 31, 2001, have Enron North America as the counterparty. Enron Corporation and various subsidiaries, including Enron North America, filed for protection from creditors under Chapter 11 of the United States Bankruptcy Code on December 3, 2001. In the fourth quarter of 2001, the Company took a charge of $37.4 million to provide an allowance for forward financial positions and to establish an allowance for uncollectible accounts related to previously settled financial and physical positions with Enron. In the first quarter of 2002, the Company recorded a cash recovery of approximately $22.1 million resulting in a gain of approximately $14.0 million as a result of an agreement to sell the related Enron claim to a third party. The sale of the Enron claim is subject to normal representations as to the validity of the claims and the guarantees from Enron.

The filing of the voluntary bankruptcy proceeding by Enron created a possible technical default related to various financing leases tied to the Company s Bushton gas processing plant in south central Kansas. The Company acquired the Bushton gas processing plant and related leases from Kinder Morgan, Inc. (KMI) in April 2000. KMI had previously acquired the plant and leases from Enron. Enron is one of three guarantors of these Bushton plant leases. However, the Company is the primary guarantor. In January 2002, the Company was granted a waiver on the possible technical default related to these leases. The Company will continue to make all payments due under these leases.

Westar Energy In May 2002, Westar Energy, Inc. (formerly known as Western Resources, Inc.) and its wholly owned subsidiary, Westar Industries, Inc., delivered a sale notice to the Company giving notice of Westar s intent to sell 4,714,434 shares of the Company s common stock and 19,946,448 shares of the Company s Series A Convertible Preferred Stock, representing all of the Company s common and preferred stock held by Westar.

The delivery of the sale notice to the Company gives the Company or its designee the option to purchase all, but not less than all, of the common and preferred stock held by Westar at a price equal to 98.5% of the average of the closing prices of the Company s common stock during the 20 trading days prior to the date of the sale notice, which equals $21.77 per share for a total purchase price of approximately $971 million. The purchase period is 90 days after the date of notice and expires August 28, 2002. This period can be extended for 30 days after any necessary regulatory approvals, but cannot exceed 180 days after the date of the sale notice. The Company is currently considering its options related to the notice.

Southwest Gas Corporation In connection with the now terminated proposed acquisition of Southwest Gas Corporation (Southwest), the Company is a party to various lawsuits.

The Company and certain of its officers, as well as Southwest and certain of its officers, and others have been named as defendants in a lawsuit brought by Southern Union Company (Southern Union). The Southern Union allegations include, but are not limited to, violations of the Racketeer Influenced and Corrupt Organizations Act and improper interference in a contractual relationship between Southwest and Southern Union. The original claim asked for not less than $750 million compensatory damages, to be trebled for racketeering and unlawful violations, and rescission of a Confidentiality and Standstill Agreement between the Company and Southern Union.

On June 29, 2001, the Company filed Motions for Summary Judgment. On September 26, 2001, the Court entered an order that, among other things, denied the Motions for Summary Judgment by the Company on Southern Union s claim for tortious interference with Southern Union s prospective relationship with Southwest. However, the Court s ruling limited any recovery by Southern Union to out-of-pocket damages and punitive damages. On June 10, 2002, the Company filed a motion for summary judgment against Southern Union as to Southern Union s sole remaining claim for tortious interference with a prospective relationship, and also moved for summary judgment on Southern Union s claim for punitive damages. Eugene Dubay and John A. Gaberino, Jr., each an officer of the Company, joined in that motion. Trial is currently scheduled to begin October 15, 2002. Based on discovery at this point, the Company believes that Southern Union s out-of-pocket damages potentially recoverable at trial, exclusive of punitive damages, legal fees and expenses, are less than $1.0 million.

Southwest filed a lawsuit against the Company and Southern Union alleging, among other things, fraud and breach of contract. On August 9, 2002, the Company settled with Southwest all claims asserted against each other in these cases in consideration for a payment of $3.0 million to be paid by the Company to Southwest.

On August 6, 2002, Southwest and Southern Union settled their claims against each other. Trial on the remaining claims asserted by Southern Union against the Company is scheduled to begin October 15, 2002.

Two substantially identical derivative actions were filed by shareholders against members of the Board of Directors of the Company alleging violation of their fiduciary duties to the Company by causing or allowing the Company to engage in certain fraudulent and improper schemes related to the planned acquisition of Southwest and waste of corporate assets. These two cases have been consolidated. They allege conduct by the Company caused the Company to be sued by both Southwest and Southern Union, which exposed the Company to millions of dollars in liabilities. The plaintiffs seek an award of compensatory and punitive damages and costs, disbursements and reasonable attorney fees. The Company and its independent directors and officers named as defendants filed Motions to Dismiss the action for failure of the plaintiffs to make a pre-suit demand on the Company s Board of Directors. In addition, the independent directors and certain officers filed Motions to Dismiss the action for failure to state a claim. On February 26, 2001, the action was stayed until one of the parties notifies the Court that a dissolution of the stay is requested.

Except as set forth above, the Company is unable to estimate the possible loss, if any, associated with these matters. If substantial damages were ultimately awarded, this could have a material adverse effect on the Company s results of operations, cash flows and financial position. The Company is defending itself vigorously against all claims asserted by Southern Union and all other matters relating to the now terminated proposed acquisition of Southwest.

Environmental The Company has 12 manufactured gas sites in Kansas, which were acquired in 1997, that may contain potentially harmful materials classified as hazardous. Hazardous materials are subject to control or remediation under various state and federal environmental laws and regulations. A consent agreement with the Kansas Department of Health and Environment (KDHE) presently governs all future work at these sites. The terms of the consent agreement allow the Company to investigate and set remediation priorities for these sites based upon the results of the investigations and risk analysis. The prioritized sites will be investigated over a period of time as negotiated with the KDHE. Through June 30, 2002, the costs of the investigation and risk analysis related to these manufactured gas sites have been immaterial.

Although remedial investigation and interim clean up has begun on four sites, limited information is available about the sites. Management s best estimate of the cost of remediation ranges from $100,000 to $10 million per site based on a limited comparison of costs incurred to remediate comparable sites. These estimates do not give effect to potential insurance recoveries, recoveries through rates or recoveries from unaffiliated parties. The KCC has permitted others to recover remediation costs through rates. It should be noted that additional information and testing could result in costs significantly below or in excess of current estimates. To the extent that such remediation costs are not recovered, the costs could be material to the Company s results of operations and cash flows depending on the remediation done and number of years over which the remediation is completed.

In January 2001, the Company s Yaggy gas storage facility, located in Hutchison, Kansas, was idled following a series of natural gas explosions and eruptions of natural gas geysers. In July 2002, the KDHE issued an administrative order that assesses a $180,000 civil penalty against the Company, based on alleged violations of several KDHE regulations. The Company is currently assessing if it will appeal this order. The Company believes there are no long-term environmental effects from the Yaggy storage facility.

Other The OCC staff filed an application on February 1, 2001 to review the gas procurement practices of ONG in acquiring its gas supply for the 2000/2001 heating season and to determine if these practices were consistent with least cost procurement practices and whether the Company s procurement decisions resulted in fair, just and reasonable costs being borne by ONG customers. In a hearing on October 31, 2001, the OCC issued an oral ruling that ONG not be allowed to recover the balance in the Company s unrecovered purchased gas cost (UPGC) account related to the unrecovered gas costs from the 2000/2001 winter. This was effective with the first billing cycle for the month following the issuance of a final order. A final order, issued on November 20, 2001, halted the recovery process effective December 1, 2001. On December 12, 2001, the OCC approved a request to stay the order and allowed ONG to begin collecting unrecovered gas costs, subject to refund should the Company ultimately lose the case. In the fourth quarter of 2001, the Company took a charge of $34.6 million as a result of this order. In May 2002, the Company, along with the staff of the Public Utility Division and the Consumer Services Division of the OCC, the Oklahoma Attorney General, and other stipulating parties, entered into a joint settlement agreement resolving this gas cost issue and ongoing litigation related to a contract with Dynamic Energy Resources, Inc.

The settlement agreement has a $33.7 million value to ONG customers that will be realized over a three-year period. In July 2002, immediate cash savings were provided to all ONG customers in the form of billing credits totaling approximately $10.1 million. ONG is replacing certain gas contracts, which is expected to reduce gas costs by approximately $13.8 million due to avoided reservation fees between April 2003 and October 2005. Additional savings of approximately $8.0 million from the use of storage service in lieu of those contracts are expected to occur between November 2003 and March 2005. Any expected savings from the use of storage that are not achieved and a $1.8 million credit will be added to the final billing credit scheduled to be provided to customers in December 2005. As a result of this settlement agreement, the Company revised its estimate of the charge taken in the fourth quarter of 2001 downward by $14.2 million to $20.4 million and recorded the adjustment in the second quarter of 2002 as a decrease to cost of gas.

Two separate class action lawsuits have been filed against the Company in connection with the natural gas explosions and eruptions of natural gas geysers that occurred at the Yaggy storage facility in Hutchinson, Kansas in January 2001. Although no assurances can be given, the Company believes that the ultimate resolution of these matters will not have a material adverse effect on its financial position or results of operations. The Company and its subsidiaries are represented by their insurance carrier in these cases. The Company is vigorously defending itself against all claims.

The Company is a party to other litigation matters and claims, which are normal in the course of its operations, and while the results of litigation and claims cannot be predicted with certainty, management believes the final outcome of such matters will not have a materially adverse effect on the Company s consolidated results of operations, financial position, or liquidity.

F. Segments

Management has divided the Company s operations into the following six reportable segments based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment: (1) the Marketing and Trading segment markets natural gas to wholesale and retail customers and markets electricity to wholesale customers; (2) the Gathering and Processing segment gathers and processes natural gas and fractionates, stores and markets natural gas liquids; (3) the Transportation and Storage segment transports and stores natural gas for others and buys and sells natural gas; (4) the Distribution segment distributes natural gas to residential, commercial and industrial customers, leases pipeline capacity to others and provides transportation services for end-use customers; (5) the Production segment develops and produces natural gas and oil; and (6) the Other segment primarily operates and leases the Company s headquarters building and a related parking facility.

During the first quarter of 2002, the Power segment was combined with the Marketing and Trading segment, eliminating the Power segment. This presentation reflects the Company s strategy of trading around the Company s recently completed electric generating power plant. The prior period has been restated to reflect this combination.

The accounting policies of the segments are substantially the same as those described in the Summary of Significant Accounting Policies in the Company s Annual Report on Form 10-K for the year ended December 31, 2001. Intersegment sales are recorded on the same basis as sales to unaffiliated customers. Corporate overhead costs relating to a reportable segment are allocated for the purpose of calculating operating income. The Company s equity method investments do not represent operating segments of the Company. The Company has no single external customer from which it receives ten percent or more of its consolidated revenues.

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

Three Months Ended June 30, 2002	Marketing and Trading	Gathering and Processing	Transportation and Storage	Distribution	Production	Other and Eliminations	Total
				(Thousands of Dollars)			
Sales to unaffiliated customers	$ 729,924	$ 189,051	$ 18,986	$ 211,663	$ 20,587	$ 1,233	$ 1,171,444
Intersegment sales	69,565	79,054	23,600	1,100	3,804	(177,123)	$
Total Revenues	$ 799,489	$ 268,105	$ 42,586	$ 212,763	$ 24,391	$ (175,890)	$ 1,171,444
Net revenues	$ 67,177	$ 44,559	$ 27,214	$ 91,444	$ 24,391	$ 134	$ 254,919
Operating costs	$ 8,076	$ 35,940	$ 16,556	$ 54,745	$ 7,809	$ 2,500	$ 125,626
Depreciation, depletion and amortization	$ 1,465	$ 8,591	$ 5,471	$ 19,575	$ 9,483	$ 391	$ 44,976
Operating income	$ 57,636	$ 28	$ 5,187	$ 17,124	$ 7,099	$ (2,757)	$ 84,317
Income from equity investments	$	$	$ 24	$	$	$ 438	$ 462
Capital expenditures	$ 1,442	$ 14,007	$ 9,741	$ 32,403	$ 11,349	$ 4,080	$ 73,022

Three Months Ended June 30, 2001	Marketing and Trading	Gathering and Processing	Transportation and Storage	Distribution	Production	Other and Eliminations	Total
				(Thousands of Dollars)			
Sales to unaffiliated customers	$ 909,114	$ 218,033	$ 22,173	$ 225,051	$ 27,842	$ 186	$ 1,402,399
Intersegment sales	105,810	135,634	25,706	772	7,182	(275,104)	$
Total Revenues	$ 1,014,924	$ 353,667	$ 47,879	$ 225,823	$ 35,024	$ (274,918)	$ 1,402,399
Net revenues	$ 39,333	$ 43,080	$ 32,698	$ 72,290	$ 35,024	$ (1,470)	$ 220,955
Operating costs	$ 2,383	$ 29,219	$ 12,348	$ 61,629	$ 7,149	$ (1,571)	$ 111,157
Depreciation, depletion and amortization	$ 142	$ 6,995	$ 4,751	$ 17,159	$ 8,159	$ 650	$ 37,856
Operating income	$ 36,808	$ 6,866	$ 15,599	$ (6,498)	$ 19,716	$ (549)	$ 71,942
Income (loss) from equity investments	$	$	$ 849	$	$ 39	$ (86)	$ 802
Capital expenditures	$ 11,975	$ 9,562	$ 7,308	$ 30,216	$ 14,959	$ 8,957	$ 82,977

Six Months Ended June 30, 2002	Marketing and Trading	Gathering and Processing	Transportation and Storage	Distribution	Production	Other and Eliminations	Total
				(Thousands of Dollars)			
Sales to unaffiliated customers	$ 1,503,488	$ 346,093	$ 38,115	$ 709,648	$ 37,425	$ 2,333	$ 2,637,102
Intersegment sales	208,485	137,607	53,674	2,244	6,623	(408,633)	$
Total Revenues	$ 1,711,973	$ 483,700	$ 91,789	$ 711,892	$ 44,048	$ (406,300)	$ 2,637,102
Net revenues	$ 139,086	$ 85,882	$ 63,946	$ 229,439	$ 44,048	$ 90	$ 562,491
Operating costs	$ 16,241	$ 68,010	$ 31,221	$ 117,630	$ 15,104	$ 1,808	$ 250,014
Depreciation, depletion and amortization	$ 2,648	$ 16,561	$ 10,045	$ 36,524	$ 18,657	$ 777	$ 85,212
Operating income	$ 120,197	$ 1,311	$ 22,680	$ 75,285	$ 10,287	$ (2,495)	$ 227,265
Income (loss) from equity investments	$	$	$ 462	$	$	$ (1,015)	$ (553)
Total assets	$ 1,511,871	$ 1,231,211	$ 818,742	$ 1,719,809	$ 327,957	$ 96,541	$ 5,706,131
Capital expenditures	$ 1,580	$ 24,815	$ 24,500	$ 53,524	$ 22,971	$ 6,482	$ 133,872

Six Months Ended June 30, 2001	Marketing and Trading	Gathering and Processing	Transportation and Storage	Distribution	Production	Other and Eliminations	Total
				(Thousands of Dollars)			
Sales to unaffiliated customers	$ 2,777,234	$ 491,720	$ 57,013	$ 986,226	$ 44,681	$ 2,449	$ 4,359,323
Intersegment sales	525,848	338,539	44,069	1,505	19,629	(929,590)	$
Total Revenues	$ 3,303,082	$ 830,259	$ 101,082	$ 987,731	$ 64,310	$ (927,141)	$ 4,359,323
Net revenues	$ 68,614	$ 92,305	$ 70,259	$ 213,062	$ 64,310	$ 3,266	$ 511,816
Operating costs	$ 6,805	$ 58,396	$ 25,237	$ 119,694	$ 14,954	$ (3,069)	$ 222,017
Depreciation, depletion and amortization	$ 298	$ 13,806	$ 9,501	$ 34,136	$ 15,744	$ 1,326	$ 74,811
Operating income	$ 61,511	$ 20,103	$ 35,521	$ 59,232	$ 33,612	$ 5,009	$ 214,988
Cumulative effect of a change in accounting principle, net of tax	$	$	$	$	$ (2,151)	$	$ (2,151)
Income from equity investments	$	$	$ 1,508	$	$ (141)	$ 4,842	$ 6,209
Total assets	$ 1,987,556	$ 1,247,510	$ 643,849	$ 1,844,662	$ 319,293	$ (107,173)	$ 5,935,697
Capital expenditures	$ 40,358	$ 16,713	$ 18,122	$ 57,394	$ 26,220	$ 15,183	$ 173,990

G. Paid in Capital

Paid in capital is $338.8 million and $338.1 million for common stock at June 30, 2002, and December 31, 2001, respectively. Paid in capital for convertible preferred stock was $564.2 million at June 30, 2002, and December 31, 2001.

H. Derivative Instruments and Hedging Activities

On January 1, 2001, the Company adopted the provisions of Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (Statement 133), amended by Statement No. 137 and Statement No. 138. Statement 137 delayed the implementation of Statement 133 until fiscal years beginning after June 15, 2000. Statement 138 amended the accounting and reporting standards of Statement 133 for certain derivative instruments and hedging activities. Statement 138 also amends Statement 133 for decisions made by the Financial Accounting Standards Board (FASB) relating to the Derivatives Implementation Group (DIG) process. The DIG is addressing Statement 133 implementation issues, the ultimate resolution of which may impact the application of Statement 133.

Under Statement 133, entities are required to record all derivative instruments in the balance sheet 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, on the reason for holding it. If certain conditions are met, entities may elect to designate a derivative instrument as a hedge of exposures to changes in fair values, cash flows, or foreign currencies. If the hedged exposure is a fair value exposure, 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. If the hedged exposure is a cash flow exposure, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of other comprehensive income (outside earnings) and subsequently reclassified into earnings when the forecasted transaction affects earnings. Any amounts excluded from the assessment of hedge effectiveness, as well as the ineffective portion of the hedge, are reported in earnings immediately.

In 2000, the Company entered into derivative instruments related to the production of natural gas, most of which expired by the end of 2001. These derivative instruments were designed to hedge the Company s Production segment s exposure to changes in the price of natural gas. Changes in the fair value of the derivative instruments were reflected initially in other comprehensive income (loss) and subsequently realized in earnings when the forecasted transaction affected earnings. At the adoption of Statement 133, the Company recorded a cumulative effect charge of $2.2 million, net of tax, in the income statement and $28 million, net of tax, in accumulated other comprehensive loss to recognize at fair value the ineffective and effective portions, respectively, of the losses on all derivative instruments that were designated as cash flow hedging instruments, which primarily consisted of no cost option collars and swaps on natural gas production.

The Company realized gains in earnings of approximately $0.6 million and $1.3 million for the three and six months ended June 30, 2002, respectively, related to production hedges entered into in 2002. These realized gains were reclassified from accumulated other comprehensive income resulting from the settlement of contracts when the natural gas was sold. The gains are reported in operating revenues. Other comprehensive income for the three and six months ended June 30, 2002 includes approximately $2.6 million and $1.8 million, respectively, related to a cash flow exposure for production hedges and will be realized in earnings within the next 30 months.

The Company is subject to the risk of fluctuation in interest rates in the normal course of business. The Company manages interest rate risk through the use of fixed rate debt, floating rate debt and, at times, interest rate swaps. In July 2001, the Company entered into interest rate swaps on a total of $400 million in fixed rate long-term debt. The interest rate under these swaps resets periodically based on the three-month London InterBank Offered Rate (LIBOR) or the six-month LIBOR rate at the reset date. In October 2001, the Company entered into an agreement to lock in the interest rates for each reset period under the swap agreements through the first quarter of 2003. In December 2001, the Company entered into interest rate swaps on a total of $200 million in fixed rate long-term debt. These swaps were designated as fair value hedges. Price risk management assets include $30.7 million to recognize the fair value of the Company s derivatives that are designated as fair value hedging instruments in June 2002. Long-term debt includes approximately $29.3 million to recognize the change in fair value of the related hedged liability. The Company also increased interest expense by $0.8 million for the three months ended June 30, 2002 to recognize the ineffectiveness caused by locking the LIBOR rates into future periods.

I. Comprehensive Income

The tables below give an overview of comprehensive income for the three and six months ended June 30, 2002 and 2001. Other comprehensive income for the three and six months ended June 30, 2002 includes unrealized gains on derivative instruments, unrealized holding gains arising during the period relating to the investment in Magnum Hunter Resources (MHR) and realized gains on derivative instruments and the sale of the Company s common stock ownership in MHR.

In March 2002, the Company began accounting for its investment in MHR as an available-for-sale security and, accordingly, marked the investment to fair value through other comprehensive income. This is a result of MHR s merger with Prize Energy Corp. (Prize), which reduced the Company s direct ownership in MHR to approximately 11 percent and reduced the number of MHR board of director positions held by the Company from two to one. In April and June 2002, the Company sold its common stock ownership in MHR.

Other comprehensive income for the three and six months ended June 30, 2001 includes the cumulative effect of a change in accounting principle due to the adoption of Statement 133 and unrealized gains and realized losses on derivative instruments.

	Three Months Ended June 30, 2002		Six Months Ended June 30, 2002	
		(Thousands of Dollars)		
Net Income		**$ 35,383**		**$ 107,981**
Other comprehensive income (loss):				
Unrealized gains on derivative instruments	**$ 2,586**		**$ 1,786**	
Unrealized holding gains (losses) arising during the period	**(115)**		**13,927**	
Realized gains in net income	**(13,227)**		**(13,961)**	
Other comprehensive income before taxes	**(10,756)**		**1,752**	
Income tax benefit (expense) on other comprehensive income (loss)	**3,858**		**(719)**	
Other comprehensive income (loss)		**$ (6,898)**		**$ 1,033**
Comprehensive income		**$ 28,485**		**$ 109,014**

	Three Months Ended June 30, 2001		Six Months Ended June 30, 2001	
		(Thousands of Dollars)		
Net Income		$ 23,608		$ 88,467
Other comprehensive income:				
Cumulative effect of a change in accounting principle	$		$ (45,556)	
Unrealized gains on derivative instruments	10,300		22,726	
Realized losses in net income	5,179		26,015	
Other comprehensive income before taxes	15,479		3,185	
Income tax benefit on other comprehensive income	(5,987)		(1,231)	
Other comprehensive income		$ 9,492		$ 1,954
Comprehensive income		$ 33,100		$ 90,421

Accumulated other comprehensive loss of $0.7 million at June 30, 2002, includes unrealized and realized gains and losses on derivative instruments, unrealized and realized holding gains and losses related to the investment in MHR and minimum pension liability adjustments.

J. Goodwill

The Company adopted Statement of Financial Accounting Standards No. 142 on January 1, 2002. Under Statement 142, goodwill is no longer amortized but reviewed for impairment annually or more frequently if certain indicators arise. Statement 142 prescribes a two phase process for testing the impairment of goodwill. The first phase, required to be completed by June 30, 2002, identifies indicators for impairment. If an impairment is indicated, the second phase, required to be completed by December 31, 2002, measures the impairment. In accordance with the provisions of Statement 142, the Company has performed the first of the required impairment tests of goodwill and, based upon this transition impairment test, no impairment to goodwill was indicated and the Company will not record a charge in connection with the adoption of this standard. Had the Company been accounting for its goodwill under Statement 142 for all periods presented, the Company s net income and income per share would have been as follows:

	Six Months Ended June 30,	
	2002	2001
	(Thousands of Dollars)	
Reported net income	**$ 107,981**	$ 88,467
Add back goodwill amortization, net of tax		1,348
Pro forma adjusted net income	**$ 107,981**	$ 89,815
Basic net income per share:		
Reported net income	**$ 0.90**	$ 0.74
Goodwill amortization, net of tax		0.01
Pro forma adjusted basic net income per share	**$ 0.90**	$ 0.75
Diluted net income per share:		
Reported net income	**$ 0.89**	$ 0.74
Goodwill amortization, net of tax		0.01
Pro forma adjusted diluted net income per share	**$ 0.89**	$ 0.75

The changes in the carrying amount of goodwill for the six months ended June 30, 2002 and 2001 are as follows:

	Balance December 31, 2001	Additions	Amortization	Balance June 30, 2002
		(Thousands of Dollars)		
Marketing and Trading	$ 5,616	$	$	$ 5,616
Gathering and Processing	34,343			34,343
Transportation and Storage	37,842			37,842
Distribution	35,709			35,709
Production	358			358
Total consolidated	$ 113,868	$	$	$ 113,868

	Balance December 31, 2000	Additions	Amortization	Balance June 30, 2001
		(Thousands of Dollars)		
Marketing and Trading	$ 5,123	$	$ (107)	$ 5,016
Gathering and Processing	17,887	20,482	(303)	38,066
Transportation and Storage	33,328	5,394	(439)	38,283
Distribution	36,703		(497)	36,206
Production	368		(5)	363
Total consolidated	$ 93,409	$ 25,876	$ (1,351)	$ 117,934

K. Subsequent Event

On August 5, 2002, the Company launched a tender offer to purchase with cash all the outstanding 8.44% Senior Notes due 2004 and the 8.32% Senior Notes due 2007 for a total purchase price of approximately $69 million. The total purchase price includes a premium of approximately $5 million to purchase the notes. The offer expires August 20, 2002. If completed, the Company will recognize the transaction in the third quarter of 2002.

On August 9, 2002, the Company settled with Southwest all claims asserted against each other related to the Company s terminated acquisition of Southwest. The claims were settled for a payment of $3.0 million to be paid by the Company to Southwest. This charge has been included in the consolidated financial statements at June 30, 2002. See Note E.

L. Restatement of Consolidated Statement of Cash Flows

The consolidated statement of cash flows for the six-month period ended June 30, 2002 has been restated to correct a mathematical error related to the treatment of bank overdrafts. The balance of bank overdrafts at June 30, 2002, and December 31, 2001, was $20.2 million and $48.9 million, respectively, which are included in accounts payable in the accompanying consolidated balance sheets. A decrease in the bank overdraft was inadvertently treated as an increase of cash. The following is a summary of the impact of the changes:

	Six Months Ended June 30, 2002
	(Thousands of Dollars)
Accounts payable and accrued liabilities:	
As previously reported	$ 18,062
As restated	$ 75,576
Cash Provided By Operating Activities:	
As previously reported	$ 585,778
As restated	$ 643,292
Change in bank overdraft:	
As previously reported	$ 28,757
As restated	$ (28,757)
Cash Used In Financing Activities:	
As previously reported	$ (493,598)
As restated	$ (551,112)

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operation

Forward Looking Statements

Some of the statements contained and incorporated in this Quarterly 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 the anticipated financial performance, management s plans and objectives for future operations, business prospects, outcome of pending litigation and regulatory proceedings, market conditions and other matters. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements in various 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 operations and other statements contained or incorporated in this report identified by words such as anticipate, estimate, expect, intend, believe, projection or goal.

You should not place undue reliance on forward-looking statements. They are based on known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the 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 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:

- the effects of weather and other natural phenomena on sales and prices;
- competition from other energy suppliers as well as alternative forms of energy;
- the capital intensive nature of our business;
- further deregulation, or unbundling of the natural gas business;
- competitive changes in the natural gas gathering, transportation and storage business resulting from deregulation, or unbundling, of the natural gas business;
- the profitability of assets or businesses acquired by us;
- risks of marketing, trading, and hedging activities as a result of changes in energy prices, creditworthiness of counterparties and government regulation;
- economic climate and growth in the geographic areas in which we do business;
- the uncertainty of gas and oil reserve estimates;
- the timing and extent of changes in commodity prices for natural gas, natural gas liquids, electricity, and crude oil;
- the effects of changes in governmental policies and regulatory actions, including income taxes, environmental compliance, and authorized rates;
- the results of litigation related to our now terminated proposed acquisition of Southwest Gas Corporation (Southwest);
- the results of administrative proceedings and litigation involving the Oklahoma Corporation Commission (OCC) and Kansas Corporation Commission (KCC);
- our ability to access capital at competitive rates;

- the effect (including the effect on our liquidity and capital resources) of a decision to purchase or not to purchase our shares of common and preferred stock held by Westar Energy, Inc.; and
- the other factors listed in the reports we have filed and may file from time to time with the Securities and Exchange Commission.

Other factors and assumptions not identified above also may have been involved in the making of 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.

Results of Operations

Consolidated Operations

We are a diversified energy company whose objective is to maximize value for shareholders by vertically integrating our business operations from the wellhead to the burner tip. This strategy has led us to focus on acquiring assets that provide synergistic trading and marketing opportunities along the natural gas energy chain. Products and services are provided to our customers through the following segments:

- Marketing and Trading
- Gathering and Processing
- Transportation and Storage
- Distribution
- Production
- Other

During the first quarter of 2002, the Power segment was combined with the Marketing and Trading segment, eliminating the Power segment. All segment data has been restated to reflect this combination.

We sold and received cash for our claim related to the Enron bankruptcy for $22.1 million resulting in a gain of $14.0 million in the first quarter of 2002. The sale is subject to normal representations as to the validity of the claim and guarantees from Enron. We had previously recorded a charge of $37.4 million in the fourth quarter of 2001 related to the Enron bankruptcy.

During the second quarter of 2002, we settled a number of outstanding issues pending before the OCC. We had previously recorded a charge of $34.6 million in the fourth quarter of 2001 related to these matters. As a result of the settlement agreement, we revised the estimated amount of the charge and reversed $14.2 million of the charge in the second quarter of 2002.

On March 15, 2002, Magnum Hunter Resources (MHR) merged with Prize Energy Corp. (Prize) reducing our direct ownership to approximately 11 percent and reducing the number of positions held by us on the MHR board of directors from two to one. We began accounting for our investment in MHR as an available-for-sale security and, accordingly, marked the investment to fair value through other comprehensive income at March 31, 2002. During the second quarter of 2002, we sold the majority of our investment in MHR for a pre-tax gain of approximately $7.6 million, which is included in other income, net for the three and six months ended June 30, 2002. We retained approximately 1.5 million stock warrants. We also relinquished our remaining seat on MHR s board of directors. The MHR investment and related equity income and loss are reported in the Other segment.

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

Financial Results	Three Months Ended June 30, **2002**	Three Months Ended June 30, 2001	Six Months Ended June 30, **2002**	Six Months Ended June 30, 2001
	(Thousands of Dollars)			
Operating revenues	**$ 1,171,444**	$ 1,402,399	**$ 2,637,102**	$ 4,359,323
Cost of gas	**916,525**	1,181,444	**2,074,611**	3,847,507
Net revenues	**254,919**	220,955	**562,491**	511,816
Operating costs	**125,626**	111,157	**250,014**	222,017
Depreciation, depletion, and amortization	**44,976**	37,856	**85,212**	74,811
Operating income	**$ 84,317**	$ 71,942	**$ 227,265**	$ 214,988
Other income, net	**$ 5,131**	$ 566	**$ 4,411**	$ 3,865
Cumulative effect of a change in accounting principle	**$**	$	**$**	$ (3,508)
Income tax				1,357
Cumulative effect of a change in accounting principle, net of tax	**$**	$	**$**	$ (2,151)

Our operating revenues and cost of gas decreased for the three and six months ended June 30, 2002 compared to the same periods in 2001 primarily due to lower natural gas prices. Although operating revenues and cost of gas decreased in 2002 compared to 2001, our net revenues increased primarily due to increased margins from our marketing and trading business, the $14.0 million Enron recovery in the first quarter of 2002 of a portion of the costs related to Enron sales contracts that were written off in the fourth quarter of 2001, and the $14.2 million adjustment due to the OCC settlement. These increases were offset by decreases in net revenues in the Gathering and Processing, Transportation and Storage and Production segments.

Increased employee costs were part of the increase in operating costs for the three and six months ended June 30, 2002 compared to the same periods in 2001. Other changes in operating costs are discussed in the applicable segment s section.

Other income, net for the three and six months ended June 30, 2002, includes a $7.6 million gain related to the sale of our investment in MHR. This was partially offset by a $3.0 million charge for the settlement of litigation with Southwest related to our terminated acquisition of Southwest. Other income, net for the six months ended June 30, 2001, includes approximately $6.2 million in income from equity investments that was partially offset by a charge of $2.2 million related to ongoing litigation costs associated with the terminated acquisition of Southwest.

Marketing and Trading

Our Marketing and Trading segment purchases, stores, markets and trades natural gas to both wholesale and retail customers in 28 states. We have strong mid-continent region storage positions and transport capacity of approximately one Bcf/d (Bcf per day) that allows us to trade storage capacity and transportation from the California border, throughout the Rockies, to the Chicago city gate. With total storage capacity of 80 Bcf, withdrawal capability of 2.3 Bcf/d and injection capability of 1.3 Bcf/d, we have direct access to all regions of the country and flexibility to capture volatility in the energy markets. We have constructed a peak electric power generating plant that began operations in mid-2001. This 300-megawatt plant is located adjacent to one of our natural gas storage facilities and is configured to supply electric power during peak demand periods. This plant allows us to capture the spark spread premium , which is the value added by converting natural gas to electricity, during peak demand periods. We continue to enhance our strategy of focusing on higher margin business (as opposed to volume) which includes providing reliable service during peak demand periods through the use of storage.

During the first quarter of 2002, the Power segment was combined with the Marketing and Trading segment, eliminating the Power segment. This combination reflects our strategy of trading around the capacity of our electric generating plant. All segment data has been restated to reflect this combination.

The following tables set forth certain selected financial and operating information relative to our Marketing and Trading segment for the periods indicated.

	Three Months Ended June 30,		Six Months Ended June 30,	
Financial Results	**2002**	2001	**2002**	2001
	(Thousands of Dollars)			
Energy sales	**$ 799,295**	$ 1,014,411	**$ 1,711,567**	$ 3,301,824
Cost of sales	**732,312**	975,591	**1,572,887**	3,234,468
Gross margin on sales	**66,983**	38,820	**138,680**	67,356
Other revenues	**194**	513	**406**	1,258
Net revenues	**67,177**	39,333	**139,086**	68,614
Operating costs	**8,076**	2,383	**16,241**	6,805
Depreciation, depletion, and amortization	**1,465**	142	**2,648**	298
Operating income	**$ 57,636**	$ 36,808	**$ 120,197**	$ 61,511
Other expense, net	**$ (2,352)**	$	**$ (2,211)**	$

	Three Months Ended June 30,		Six Months Ended June 30,	
Operating Information	**2002**	2001	**2002**	2001
Natural gas volumes *(MMcf)*	**214,832**	200,999	**470,621**	498,352
Natural gas gross margin *($/ Mcf)*	**$ 0.20**	$ 0.19	**$ 0.17**	$ 0.13
Power volumes *(MMwh)*	**336**	73	**652**	73
Power gross margin *($/Mwh)*	**$ 2.74**	$ 12.30	**$ 1.38**	$ 12.30
Capital expenditures *(Thousands)*	**$ 1,442**	$ 11,975	**$ 1,580**	$ 40,358

Lower natural gas prices across the mid-continent region for the three months ended June 30, 2002 compared to the same period in 2001, resulted in lower energy sales and cost of sales. Natural gas sales volumes increased relative to the prior year due to slightly lower storage injection rates that allowed us to sell increased volumes. Energy sales include natural gas, power, reservation fees, crude oil, natural gas liquids, and basis. Basis is the natural gas price differential that exists between two trading locations relative to the Henry Hub price. We began actively trading crude oil and natural gas liquids in the first quarter of 2002. Gross margin on sales increased for the three months ended June 30, 2002 compared to the same period for 2001 due to our ability to successfully execute our strategy to capture higher margins, even in the current comparatively lower price environment, by trading around our asset base, arbitraging intra-month price volatility through the use of storage and transport capacity and capturing option value on gas storage and other energy assets. We also benefited from comparatively lower prices that positively impacted fuel costs associated with our long-term transportation contracts.

For the six-month period ended June 30, 2002, lower gas prices and sales volumes resulted in lower sales and cost of sales in 2002 compared to the same period in 2001. Sales volumes were lower due to relatively milder temperatures during the first quarter of 2002. Gross margin on sales increased for the six-month period in 2002 compared to the same period in 2001 due to our ability to capture higher margins by arbitraging the intra-month price volatility and capture option value on stored gas and other energy assets. In addition, we benefited by $10.4 million from the sale of our Enron claim in the first quarter of 2002. Our gross margin for the three and six months ended June 30, 2002 includes income recognized from mark-to-market accounting of approximately $66 million and $52 million, respectively.

Operating costs for the three and six months ended June 30, 2002 compared to the same periods in 2001 include increased employee costs and the addition of trading and support personnel.

Capital expenditures for the three and six months ended June 30, 2001 include construction costs of $11.6 million and $40.0 million, respectively, related to the construction of the electric generating plant, which was completed in mid-2001.

Gathering and Processing

Our Gathering and Processing segment currently has a processing capacity of 2.2 Bcf/d. The capacity associated with plants owned or leased is 1.9 Bcf/d while the proportionate amount of the plant capacity that we own an interest in but do not operate is 0.12 Bcf/d. Of the current total plant processing capacity, 0.14 Bcf/d is currently idle. Our gathering and processing segment owns a total of approximately 19,700 miles of gathering pipelines, which support our gas processing plants.

The following tables set forth certain selected financial and operating information relating to our Gathering and Processing segment for the periods indicated.

Financial Results	Three Months Ended June 30, **2002**	2001	Six Months Ended June 30, **2002**	2001
	(Thousands of Dollars)			
Natural gas liquids and condensate sales	**$ 149,156**	$ 157,300	**$ 280,505**	$ 342,687
Gas sales	**93,418**	174,855	**156,621**	439,591
Gathering, compression, dehydration and processing fees and other revenues	**25,531**	21,512	**46,574**	47,981
Cost of sales	**223,546**	310,587	**397,818**	737,954
Net revenues	**44,559**	43,080	**85,882**	92,305
Operating costs	**35,940**	29,219	**68,010**	58,396
Depreciation, depletion, and amortization	**8,591**	6,995	**16,561**	13,806
Operating income	**$ 28**	$ 6,866	**$ 1,311**	$ 20,103
Other expense, net	**$ (198)**	$	**(237)**	

Operating Information	Three Months Ended June 30, **2002**	2001	Six Months Ended June 30, **2002**	2001
Total gas gathered *(MMMBtu/d)*	**1,227**	1,347	**1,220**	1,283
Total gas processed *(MMMBtu/d)*	**1,464**	1,432	**1,411**	1,322
Natural gas liquids sales *(MBbls/d)*	**90**	71	**89**	70
Natural gas liquids produced *(MBbls/d)*	**75**	71	**70**	66
Gas sales *(MMMBtu/d)*	**337**	365	**341**	380
Capital expenditures *(Thousands)*	**$ 14,007**	$ 9,562	**$ 24,815**	$ 16,713

The decrease in natural gas liquids (NGL) and condensate sales revenues for the three months ended June 30, 2002, compared to the same period in 2001 is primarily due to a decrease in composite NGL prices and crude oil prices. The Conway OPIS composite NGL price decreased from $0.521 per gallon for the three months ended June 30, 2001 to $0.393 per gallon for the same period in 2002. These decreases are partially offset by the additional revenues generated from the NGL pipeline facilities leased at the end of 2001 that increased our access to different NGL markets and increased our NGL sales volumes in 2002 compared to 2001. In addition, NGL volumes produced and sold increased, and conversely gas volumes sold decreased, because of additional gas processed and customer elections regarding their options for processing NGL s at our Bushton facility.

Gas sales and cost of sales decreased for the three months ended June 30, 2002 compared to the same period in 2001, primarily due to decreases in natural gas prices and volumes sold in 2002. Average natural gas price for the mid-continent region decreased from $4.55 MMBtu for the three months ended June 30, 2001 to $3.15 MMBtu for the same period in 2002.

Gathering, compression, dehydration and processing fees and other revenues increased for the three months ended June 30, 2002 compared to the same period in 2001 as certain transportation revenues that were received in the first quarter of 2001 were received in the second quarter of 2002.

The increase in operating costs for the three months ended June 30, 2002 compared to the same period in 2001 is primarily due to increased customer charge offs and bad debt reserves. Additionally, we experienced increased costs for leased compression added to our existing gathering operations. We also incurred additional costs associated with the NGL pipeline facilities leased at the end of 2001.

The decrease in NGL and condensate sales revenues for the six months ended June 30, 2002, compared to the same period in 2001 is primarily due to a decrease in composite NGL prices and crude oil prices. The Conway OPIS composite NGL price decreased from $0.578 per gallon for the six months ended June 30, 2001 to $0.361 per gallon for the same period in 2002. The average NYMEX crude oil price decreased from $28.85 per barrel for the six-month period in 2001 to $22.74 per barrel for the same period in 2002. These decreases are partially offset by the additional revenues generated from the NGL pipeline facilities leased at the end of 2001 that increased our access to different NGL markets and increased our NGL sales volumes in 2002 compared to 2001. In addition, NGL volumes produced and sold increased, and conversely gas volumes sold decreased, because of the change in plant operations in the first quarter of 2001 due to the high value of natural gas relative to NGL prices.

Gas sales and cost of sales decreased for the six months ended June 30, 2002 compared to the same period in 2001, primarily due to decreases in natural gas prices. Average natural gas price for the mid-continent region decreased from $5.79 MMBtu for the six months ended June 30, 2001 to $2.68 MMBtu for the same period in 2002.

The decrease in net revenues for the six months ended June 30, 2002 compared to the same period in 2001 is primarily due the decline in NGL and natural gas prices, the relative value of NGL s compared to natural gas and the change in plant operations as a result of market conditions. We also experienced lower net revenues as a result of lower of cost or market adjustments associated with NGL inventories and losses associated with Enron s non-performance on a gas sale contract. Net revenues were also negatively impacted by the ice storm that caused plant outages across much of Oklahoma in the first quarter of 2002.

The increases in operating costs for the six months ended June 30, 2002 compared to the same period in 2001 are primarily due to increased bad debt expense. Operating costs also increased as a result of additional compression we added to our existing gathering operations and higher employee costs. We also incurred additional costs associated with the NGL pipeline facilities leased at the end of 2001.

Transportation and Storage

Our Transportation and Storage segment represents our intrastate natural gas transmission pipelines and natural gas storage facilities. We have four storage facilities in Oklahoma, two in Kansas and three in Texas, with a combined working capacity of approximately 58 Bcf, of which 8 Bcf is idled. Our intrastate transmission pipelines operate in Oklahoma, Kansas and Texas and are regulated by the OCC, KCC, and Texas Railroad Commission (TRC), respectively.

The following tables set forth certain selected financial and operating information relating to our Transportation and Storage segment for the periods indicated.

Financial Results	Three Months Ended June 30, 2002	Three Months Ended June 30, 2001	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
	(Thousands of Dollars)			
Transportation and gathering revenues	**$ 27,645**	$ 28,591	**$ 53,796**	$ 64,757
Storage revenues	**9,511**	11,384	**17,058**	21,338
Gas sales and other	**5,430**	7,904	**20,935**	14,987
Cost of fuel and gas	**15,372**	15,181	**27,843**	30,823
Net revenues	**27,214**	32,698	**63,946**	70,259
Operating costs	**16,556**	12,348	**31,221**	25,237
Depreciation, depletion, and amortization	**5,471**	4,751	**10,045**	9,501
Operating income	**$ 5,187**	$ 15,599	**$ 22,680**	$ 35,521
Other income, net	**$ 188**	$ 849	**$ 1,397**	$ 8

Operating Information	Three Months Ended June 30, 2002	Three Months Ended June 30, 2001	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
Volumes transported *(MMcf)*	**129,036**	126,940	**288,679**	286,785
Capital expenditures *(Thousands)*	**$ 9,741**	$ 7,308	**$ 24,500**	$ 18,122

Transportation and gathering revenues decreased for the three months ended June 30, 2002 compared to the same period in 2001 primarily due to the decrease in price of natural gas and its impact on the valuation of retained fuel. Storage revenue decreased for the three months ended June 30, 2002 compared to the same period in 2001 due to a decrease in available capacity resulting from idling certain storage facilities in 2001. Gas sales and other revenues decreased in the three months ended June 30, 2002 compared to the same period in 2001 due to decreases in the price of natural gas and a reduction in sales volumes associated to our wellhead purchases.

Cost of fuel and gas for the three-month period in 2002 compared to 2001 decreased as a result of lower natural gas prices for fuel and the reduction in sales volumes associated with wellhead purchases. These decreases were offset by adjustments resulting from the reconciliation of third party contractual storage and pipeline imbalance positions.

The increase in operating costs for the three-month period in 2002 compared to 2001 is primarily due to increased customer charge offs, litigation costs and ad valorem taxes. Additionally, other income, net was lower as a result of lower income distributions from our partnership interests.

Transportation and gathering revenues decreased for the six months ended June 30, 2002 compared to the same period in 2001 due to the decrease in the price of natural gas and its impact on the valuation of retained fuel. Storage revenue decreased for the six-month period in 2002 compared to the same period in 2001 due to a decrease in available storage capacity resulting from the idling of certain storage facilities in 2001. The increase in gas sales and other is due to gas inventory sales in the first quarter of 2002. This increase was partially offset by decreases in natural gas prices and sales volumes associated with our wellhead purchases.

Cost of fuel and gas decreased for the six months ended June 30, 2002 compared to the same period in 2001 due to decreases in natural gas prices for fuel and sales volumes associated with our wellhead purchases. These decreases were partially offset by adjustments resulting from the reconciliation of third party contractual storage and pipeline imbalance positions. In addition, cost of fuel and gas increased as a result of gas inventory sales in the first quarter of 2002.

The increase in operating costs for the six-month period in 2002 compared to 2001 is due primarily to increased bad debt expense, litigation costs, regulatory fees, ad valorem taxes and employee costs. Other income, net for the six months ended June 30, 2001 includes a $1.5 million insurance deductible charge related to the Yaggy storage facility.

Distribution

Our Distribution segment provides natural gas distribution services in Oklahoma and Kansas to residential, commercial and industrial customers. Our distribution operations in Oklahoma are conducted through Oklahoma Natural Gas (ONG), which serves residential, commercial, and industrial customers and leases gas pipeline capacity. Our distribution operations in Kansas are conducted through Kansas Gas Service (KGS), which serves residential, commercial, and industrial customers. Our Distribution segment provides gas service to about 80 percent of the population of Oklahoma and about 71 percent of the population of Kansas. ONG and KGS are subject to regulatory oversight by the OCC and KCC, respectively.

A January 2002 order from the OCC authorized ONG to increase the level of line loss recoveries made through the Company s line loss recovery rider. Recoveries related to throughput delivered through the ONG system were increased from 1.0% to 1.35% while recoveries related to throughput delivered through the ONEOK Gas Transportation (OGT) system, which is included in our Transportation and Storage segment, increased from 0.66% to 1.0%. All recoveries are calculated at our weighted average cost of gas for each month. The increased recovery percentages allow for a more timely recovery of costs incurred.

In May 2002, the KCC approved an order allowing the transfer of the MCMC transmission pipeline assets to KGS. The operation of these assets is regulated by the KCC. The MCMC transportation system provides access to the major natural gas producing areas in Kansas intersecting with the nine intra/interstate pipelines at 18 interconnect points, four processing plants, and approximately three producing fields effectively allowing gas to be moved throughout the state. With the transfer of these assets, KGS will be able to provide itself with firm transportation service. The order was effective July 1, 2002. The MCMC transmission pipeline assets will be transferred to KGS in the third quarter of 2002. At June 30, 2002, the MCMC assets are reported as part of our Transportation and Storage segment.

A Joint Stipulation approved by the OCC on May 16, 2002, settled a number of outstanding cases pending before the OCC. The major cases settled were the Commission s inquiry into our gas cost procurement practices during the winter of 2000/2001; an application seeking relief from improper and excessive purchased gas costs; and enforcement action against us, our subsidiaries and affiliated companies of ONG. In addition, all of the open inquiries related to the annual audits of ONG s fuel adjustment clause for 1996 to 2000 were closed as a result of this Stipulation.

The Stipulation has a $33.7 million value to ONG customers that will be realized over a three-year period. In July 2002, immediate cash savings were provided to all ONG customers in the form of billing credits totaling approximately $10.1 million. ONG is replacing certain gas contracts, which is expected to reduce gas costs by approximately $13.8 million, due to avoided reservation fees between April 2003 and October 2005. Additional savings of approximately $8.0 million from the use of storage gas are expected to occur between November 2003 and March 2005. Any expected savings from the use of storage that are not achieved and a $1.8 million credit will be added to the final billing credit scheduled to be provided to customers in December 2005. ONG operating income increased in the second quarter of 2002 compared to 2001 by $14.2 million as a result of this settlement.

The following table sets forth certain selected financial information relating to our Distribution segment for the periods indicated.

	Three Months Ended June 30,		Six Months Ended June 30,	
Financial Results	**2002**	2001	**2002**	2001
	(Thousands of Dollars)			
Gas sales	**$ 194,492**	$ 210,867	**$ 669,129**	$ 948,583
Cost of gas	**121,319**	153,533	**482,453**	774,669
Gross margin	**73,173**	57,334	**186,676**	173,914
PCL and ECT Revenues	**12,446**	10,652	**30,250**	28,782
Other revenues	**5,825**	4,304	**12,513**	10,366
Net revenues	**91,444**	72,290	**229,439**	213,062
Operating costs	**54,745**	61,629	**117,630**	119,694
Depreciation, depletion, and amortization	**19,575**	17,159	**36,524**	34,136
Operating income (loss)	**$ 17,124**	$ (6,498)	**$ 75,285**	$ 59,232
Other expense, net	**$ (585)**	$	**$ (921)**	$

The decrease in gas sales and cost of gas for the three and six months ended June 30, 2002 compared to the same periods in 2001 is primarily attributable to decreased gas costs resulting from lower market prices. Additional gas cost reductions of approximately $14.2 million for the three and six months ended June 30, 2002 resulted from the OCC Stipulation. Warmer than normal weather during the first quarter of 2002 also contributed to the decrease for the six months ended June 30, 2002. We experienced higher gas sales in the first quarter of 2001 due to colder than normal weather and high gas costs, which resulted in higher gas sales and cost of gas for the six months ended June 30, 2001.

Operating costs were down for the three and six months ended June 30, 2002 compared to the same periods in 2001 due primarily to reduced bad debt expense. Bad debt expense decreased $8.5 million and $11.0 million for the three and six months, respectively. The reduced bad debt expense was partially offset by increased employee costs. Unprecedented levels of high gas prices in the first quarter of 2001 resulted in increased bad debt expense during the three and six months ended June 30, 2001.

The following tables set forth certain operating information relating to our Distribution segment for the periods indicated.

Gross Margin per Mcf	Three Months Ended June 30, 2002	2001	Six Months Ended June 30, 2002	2001
Oklahoma				
Residential	**$ 4.43**	$ 4.87	**$ 2.43**	$ 2.51
Commercial	**$ 2.95**	$ 2.76	**$ 2.29**	$ 2.05
Industrial	**$ 2.57**	$ 1.89	**$ 1.64**	$ 1.22
Pipeline capacity leases	**$ 0.30**	$ 0.30	**$ 0.29**	$ 0.30
Kansas				
Residential	**$ 4.45**	$ 5.07	**$ 2.13**	$ 2.06
Commercial	**$ 2.80**	$ 3.28	**$ 1.70**	$ 1.60
Industrial	**$ 1.10**	$ 1.53	**$ 1.32**	$ 1.44
Wholesale	**$ 0.14**	$ 0.08	**$ 0.12**	$ 0.13
End-use customer transportation	**$ 0.49**	$ 0.51	**$ 0.61**	$ 0.65

Volumes *(MMcf)*	Three Months Ended June 30, 2002	2001	Six Months Ended June 30, 2002	2001
Gas sales				
Residential	**12,311**	10,658	**63,224**	64,430
Commercial	**4,474**	4,388	**21,707**	25,257
Industrial	**335**	518	**1,812**	2,469
Wholesale	**9,047**	6,440	**14,516**	7,758
Total volumes sold	**26,167**	22,004	**101,259**	99,914
PCL and ECT	**34,047**	29,344	**76,654**	68,775
Total volumes delivered	**60,214**	51,348	**177,913**	168,689

Residential gross margin per Mcf for our Oklahoma customers decreased for the three months ended June 30, 2002 compared to the same period in 2001 due to increased volumes in Oklahoma which resulted in customer-based fixed fees being spread over greater volumes. Commercial and industrial gross margins per Mcf for Oklahoma customers increased due to reduced volumes, which resulted in customer-based fixed fees being spread over fewer volumes.

Kansas residential, commercial and industrial gross margin per Mcf decreased for the three months ended June 30, 2002 compared to the same period in 2001 due to weather normalization. The Kansas weather normalization program adjusts revenues for residential and commercial customers each month to reflect the variance with normal weather based on a measurement of heating degree days made by stations throughout the Kansas territory. Weather for the three months ended June 30, 2002 was closer to normal while the same period of 2001 was warmer than normal. The gross margin per Mcf for residential and commercial customers was higher for the six months ended June 30, 2002 compared to the same period in 2001 due to increased weather normalization revenues.

Kansas wholesale sales, also known as as available gas sales, represent gas volumes available under contracts that exceed the needs of our residential and commercial customer base and are available for sale to other parties. The increase in wholesale sales margins for the three months ended June 30, 2002, primarily relates to higher gas prices. Wholesale sales volumes increased during the three and six months ended June 30, 2002, compared to the same periods of 2001 as fewer volumes were required to meet the needs of the residential, commercial, and industrial customers due to warmer weather, thus allowing more gas sales to wholesale customers. End-use customer transportation (ECT) margins decreased for the three and six months ended June 30, 2002 compared to the same periods in 2001 due to an increase in volumes sold to lower margin large industrial customers not using fuel oil in 2002 and additional volumes sold to irrigation customers.

The following table sets forth certain selected operating information relating to our Distribution segment for the periods indicated.

	Three Months Ended June 30,		Six Months Ended June 30,	
Operating Information	**2002**	2001	**2002**	2001
Average number of customers	**1,440,844**	1,468,896	**1,445,677**	1,473,315
Customers per employee	**620**	605	**598**	594
Capital expenditures *(Thousands)*	**$ 32,403**	$ 30,216	**$ 53,524**	$ 57,394

Certain costs to be recovered through the ratemaking process have been recorded as regulatory assets in accordance with Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation . Total regulatory assets resulting from this deferral process for our Distribution segment were approximately $228.6 million at June 30, 2002. Should unbundling of our gas services occur, certain of these assets may no longer meet the criteria of a regulatory asset and, accordingly, a write-off of regulatory assets and stranded costs may be required. We do not anticipate that such a write-off of costs, if any, will be material.

Production

Our Production segment owns, develops and produces natural gas and oil reserves primarily in Oklahoma, Kansas and Texas. Our strategy is to add value not only to our existing oil and gas production operations, but also to the related marketing, gathering, processing, transportation and storage businesses. Accordingly, we focus on exploitation activities rather than exploratory drilling.

The following tables set forth certain financial and operating information relating to our Production segment for the periods indicated.

Financial Results	Three Months Ended June 30, 2002	2001	Six Months Ended June 30, 2002	2001
	(Thousands of Dollars)			
Natural gas sales	**$ 20,340**	$ 32,188	**$ 37,735**	$ 58,741
Oil sales	**3,111**	2,787	**5,256**	5,440
Other revenues	**940**	49	**1,057**	129
Net revenues	**24,391**	35,024	**44,048**	64,310
Operating costs	**7,809**	7,149	**15,104**	14,954
Depreciation, depletion, and amortization	**9,483**	8,159	**18,657**	15,744
Operating income	**$ 7,099**	$ 19,716	**$ 10,287**	$ 33,612
Other income (expense), net	**$ (130)**	$ 776	**$ (88)**	$ 1,178
Cumulative effect of change in accounting principle, before tax	**$**	$	**$**	$ (3,508)

Operating Information	Three Months Ended June 30, 2002	2001	Six Months Ended June 30, 2002	2001
Proved reserves				
Gas *(MMcf)*			**238,528**	250,403
Oil *(MBbls)*			**4,724**	4,299
Production				
Gas *(MMcf)*	**6,206**	6,528	**12,565**	12,650
Oil *(MBbls)*	**114**	106	**236**	201
Average realized price (a)				
Gas *(Mcf)*	**$ 3.28**	$ 4.93	**$ 3.00**	$ 4.64
Oil *(Bbls)*	**$ 27.29**	$ 26.29	**$ 22.27**	$ 27.06
Capital expenditures (Thousands)	**$ 11,349**	$ 14,959	**$ 22,971**	$ 26,220

(a) Average realized price reflects the impact of hedging activities.

Natural gas sales decreased for the three and six months ended June 30, 2002, compared to the same periods in 2001, due to the decrease in gas prices. The gas volumes produced for the three months ended June 30, 2002 compared to the same period in 2001 decreased due to normal production declines. Sales for the six months ended June 30, 2002, includes a recovery of $2.7 million related to the sale of our Enron claim on hedging contracts. At June 30, 2002 approximately 61% of our remaining anticipated 2002 natural gas production is hedged at an average wellhead price of $3.51/Mcf.

The increase in oil sales for the three-month period ended June 30, 2002, compared to the same period in 2001, is due to both increased production volumes of oil and an increase in the average realized sales price resulting from higher market prices.

Operating costs increased for the three and six months ended June 30, 2002 compared to the same periods in 2001 due to additional employee costs as well as higher workover costs and lower overhead recovery from producing wells. The lower overhead recovery relates to a decrease in the allowable rate of recovery set by the Council of Petroleum Accounting Societies (COPAS). The increased costs were partially offset by lower production taxes resulting from lower natural gas and oil prices. Production taxes are calculated based on wellhead prices rather than realized prices. The increase in depreciation, depletion, and amortization for the three and six months ended June 30, 2002 compared to the same periods in 2001 is due to a higher rate per unit of production, caused by higher capital costs incurred in the last twelve months.

Our Production segment added 21.1 Bcfe of net reserves for the six months ended June 30, 2002 after adjustments, including 14.1 Bcfe proved developed, 2.0 Bcfe proved behind pipe, and 5.0 Bcfe proved undeveloped.

Financial Flexibility and Liquidity

Liquidity and Capital Resources

A part of our strategy has been and continues to be growth through acquisitions that strengthen and complement our existing assets. We have relied primarily on a combination of operating cash flow and borrowings from a combination of commercial paper, bank lines of credit, and 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. During 2001 and the first six months of 2002, our capital expenditures were financed through operating cash flows and short and long-term debt.

Financing is provided through our commercial paper program, long-term debt and, if needed, through a revolving credit facility. Other options to obtain financing include, but are not limited to, issuance of equity, asset securitization and sale/leaseback of facilities. We currently have a $500 million shelf registration in effect covering debt securities (including convertible debt) and common stock.

On August 5, 2002, the Company launched a tender offer to purchase with cash all the outstanding 8.44% Senior Notes due 2004 and the 8.32% Senior Notes due 2007 for a total purchase price of approximately $69 million. The total purchase price includes a premium of approximately $5 million to purchase the notes. The offer expires August 20, 2002. The Company will recognize the transaction in the third quarter of 2002. See Note K of Notes to Consolidated Financial Statements.

Our credit rating is currently A2 under review for possible downgrade by Moody s and A by Standard and Poors. Our credit rating 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 rating are the debt to capital ratio, pre-tax and after-tax interest coverage and liquidity. If our credit rating were downgraded, the interest rates on our commercial paper would increase resulting in an increase in our cost to borrow funds. 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 an $850 million revolving credit facility. In June 2002, we entered into a 90-day extension of the revolving credit facility, which expires September 30, 2002 and which we expect to renew on or prior to the present maturity date. In addition, downgrades in our credit rating could impact our Marketing and Trading segment s ability to do business by requiring the Company to post margins with the few counterparties with which we have a Credit Support Annex within our International Swaps and Derivatives Association Agreement. For further discussion of rating triggers, see the Liquidity and Capital Resources section of our Annual Report on Form 10-K for the year ended December 31, 2001.

Our energy marketing and trading business relies upon the investment grade rating of our senior unsecured long-term debt to satisfy credit support requirements with several counterparties. If our credit ratings were to decline below investment grade, our ability to participate in energy marketing and trading activity could be significantly limited. Without an investment grade rating, we would be required to fund margin requirements under industry standard derivative agreements with cash, letters of credit or other negotiable instruments. At June 30, 2002, the total notional amounts that could require such funding in the event of a credit rating decline to below investment grade is approximately $65 million.

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 gas held in storage, recoverability and timing of recovery of regulated natural gas costs, 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.

Westar Energy Sale Notice. Westar Energy, Inc. (formerly known as Western Resources, Inc.) and its affiliates beneficially own approximately 42.5% of our outstanding common stock after giving effect to the conversion of the outstanding shares of our Series A convertible preferred stock held by an affiliate of Westar. On May 30, 2002, pursuant to our shareholder agreement with Westar, Westar notified us that it intends to dispose of all of the shares of our stock that it beneficially owns, which include 4,714,434 shares of our common stock and 19,946,448 shares of our Series A convertible preferred stock that are convertible into 39,892,896 shares of our common stock at Westar s option, subject to certain conditions. Under the shareholder agreement, we have a period of 90 days after the date that Westar notified us of its intention to dispose of our shares and 30 days from the date of receipt of all necessary regulatory approvals, but in no event more than 180 days from the date of the sale notice, within which to effect the purchase of all, but not less than all, of the shares specified in the notice at a price of $21.77 per share, for a total purchase price of approximately $971.1 million. Assuming that all regulatory approvals have been received, we believe that our right to repurchase the shares expires on August 28, 2002. If we do not elect to purchase the shares specified in Westar s notice to us or agree to provide Westar with price protection in accordance with the shareholder agreement, Westar would have 16 months from May 30, 2002 to dispose of those shares in accordance with the terms and conditions of the shareholder agreement.

Our Board of Directors has formed a special committee, consisting of all directors other than the two members of the Board designated by Westar, to consider, review and evaluate the potential actions we may take in response to the Westar sale notice and to make recommendations with respect to those potential actions to our full Board of Directors. The special committee is currently evaluating our alternatives with respect to the possible repurchase of our stock owned by Westar. We cannot assure you that we will elect to purchase the shares. If we were to elect to purchase the shares, we would need to secure additional financing to complete the purchase. Financing may not be available on acceptable terms or at all. Any such financing could involve the incurrence of a significant amount of debt, which would substantially increase our leverage and may adversely effect our creditworthiness. In addition, any such financing, whether debt or otherwise, could contain covenants that restrict our operations or lead to a reduction in our credit ratings or an increase in our cost of capital and reduction in availability of capital, any of which could have a material adverse effect on our business, financial condition, results of operations and cash flows. We also may seek to finance a portion of the purchase with the proceeds generated through other financing transactions. There can be no assurance that we will be able to effect any such financing transactions on acceptable terms or at all. In addition, any election to purchase our shares from Westar would affect our ability to effect future financings, to make capital expenditures or acquisitions and to take advantage of other significant business opportunities that may arise, and may otherwise restrict corporate activities.

Enron. Enron North America is the counterparty in certain of the financial instruments discussed in our Annual Report on Form 10-K for the year-ended December 31, 2001. Enron Corporation and various subsidiaries, including Enron North America (Enron), filed for protection from creditors under Chapter 11 of the United States Bankruptcy Code on December 3, 2001. In 2001, we took a charge of $37.4 million to provide an allowance for forward financial positions and to establish an allowance for uncollectible accounts related to previously settled financial and physical positions with Enron. In the first quarter of 2002, we recorded a recovery of approximately $14.0 million as a result of an agreement to sell our Enron claim to a third party, which is subject to normal representations as to the validity of the claims and the guarantees from Enron.

The filing of the voluntary bankruptcy proceeding by Enron created a possible technical default related to various financing leases tied to our Bushton gas processing plant in south central Kansas. We acquired the Bushton gas processing plant and related leases from Kinder Morgan, Inc. (KMI) in April 2000. KMI had previously acquired the plant and leases from Enron. Enron is one of three guarantors of the Bushton plant lease. We are the primary guarantor. In January 2002, we were granted a waiver on the possible technical default related to these leases. We will continue to make all payments due under these leases.

Oklahoma Corporation Commission. The OCC staff filed an application on February 1, 2001 to review the gas procurement practices of our ONG division in acquiring its gas supply for the 2000/2001 heating season to determine if these procurement practices were consistent with least cost procurement practices and whether ONG s decisions resulted in fair, just and reasonable costs to its customers. On November 20, 2001, the OCC entered an order stating that ONG not be allowed to recover the balance in ONG s unrecovered purchased gas cost (UPGC) account related to the unrecovered gas costs from the 2000/2001 winter effective with the first billing cycle for the month following the issuance of a final order. This order halted ONG s recovery process effective December 1, 2001. On December 12, 2001, the OCC approved a request to stay the order and allowed ONG to begin collecting unrecovered gas costs, subject to refund should ONG ultimately lose the case. In the fourth quarter of 2001, we took a charge of $34.6 million as a result of this OCC order. In April 2002, we, along with the staff of the Public Utility Division and the Consumer Services Division of the OCC, the Oklahoma Attorney General, and other stipulating parties filed a joint agreement proposing settlement of this and other issues. A hearing with the OCC was held in May 2002 and an order approving the settlement was issued at that time. As a result, we recorded a $14.2 million recovery in the second quarter of 2002 and have the potential of an additional $8.0 recovery before December 2005 depending upon the potential value that could be generated by gas storage savings.

Cash Flow Analysis

Operating Cash Flows. Operating cash flows for the six months ended June 30, 2002, were $643.3 million compared to $254.3 million for the same period one year ago. The changes in operating cash flows primarily reflect changes in working capital accounts, mark-to-market income, deferred income taxes and price risk management assets and liabilities. Operating cash flows were positively impacted in the six months ended June 30, 2002 due to the collection of accounts receivable and reduced deposits. Receivables decreased for the six-month period due to the decrease in energy prices and receivables are typically higher during the heating season resulting in increased cash receipts in the first six months of the year. A reduction in restricted deposits for the Marketing and Trading segment is due to increased purchases of option contracts during the six months ended June 30, 2002. The decrease in inventories during the six months ended June 30, 2002 is partially due to the decrease in natural gas prices for the six-month period.

In addition, inventories are typically higher at December 31 and are used throughout the remainder of the winter. The change in inventories excludes the change in the Marketing and Trading segment s gas in storage, which is included in price risk management assets. The change in unrecovered purchased gas costs is due to the recovery of outstanding receivables from the 2000/2001 winter.

For the six months ended June 30, 2001, the changes in cash flow provided by operating activities are primarily due to the higher gas prices. Accounts receivable and accounts payable are typically higher during the heating season. However, they were higher than normal at December 31, 2000 due to the higher gas prices and integration of the businesses we acquired in 2000. The increase in inventories during the six months ended June 30, 2001 is a result of increased volumes in storage as well as higher gas prices as we focused on opportunistically securing volumes that are then hedged at favorable winter/summer spreads.

Investing Cash Flows. Cash paid for capital expenditures for the six months ended June 30, 2002 was $133.9 million. For the same period in 2001, capital expenditures were $174.0 million, which included $40.0 million for the construction of our electric generating plant that was completed in the second quarter of 2001. Acquisitions were $3.5 million and $15.3 million for the six months ended June 30, 2002 and 2001, respectively.

Financing Cash Flows. Our capitalization structure is 47 percent equity and 53 percent long-term debt at June 30, 2002, compared to 42 percent equity and 58 percent long-term debt at December 31, 2001. At June 30, 2002, we had $1.5 billion of long-term debt outstanding. As of that date, we could have issued $1.1 billion of additional long-term debt under the most restrictive provisions contained in our various borrowing agreements.

Our $850 million revolving credit facility is primarily used to support our commercial paper program. At June 30, 2002, $351.1 million of commercial paper was outstanding, which includes approximately $43.7 million in temporary investments.

Impact of Recently Issued Accounting Pronouncements

In July 2001, the FASB issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (Statement 143). Statement 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Statement 143 is effective for fiscal years beginning after June 15, 2002. We are currently assessing the impact of Statement 143 on our financial condition and results of operations.

In April 2002, the FASB issued Statement of Financial Accounting Standards No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13 and Technical Corrections (Statement 145). Statement 145 rescinds FASB Statement No. 4, Reporting Gains and Losses from Extinguishment of Debt (Statement 4), and an amendment to that Statement, FASB Statement No. 64 Extinguishment of Debt Made to Satisfy Sinking-Fund Requirements (Statement 64). Statement 145 also rescinds FASB Statement No. 13, Accounting for Leases (Statement 13) to eliminate the inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. Statement 145 also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings or describe their applicability under changed conditions. The provisions of Statement 145 related to the rescission of Statement 4 are effective for fiscal years beginning after May 15, 2002. If our tender offer to purchase our 8.44% Senior Notes due 2004 and 8.32% Senior Notes due 2007 is successful, we will record a charge in the third quarter of 2002 in accordance with Statement 145 related to the extinguishment of this debt. See Note K of the Notes to the Consolidated Financial Statements. The provisions of Statement 145 related to Statement 13 are effective prospectively for transactions occurring after May 15, 2002. All other provisions of Statement 145 are effective prospectively for financial statements issued on or after May 15, 2002.

In July 2002, the FASB issued Statement of Financial Accounting Standards No. 146, Accounting for Restructuring Costs (Statement 146). Under Statement 146, a company will record a liability for a cost associated with an exit or disposal activity when that liability is incurred and can be measured at fair value. Statement 146 also provides guidance on accounting for specified employee and contract terminations that are part of restructuring activities. Statement 146 is effective prospectively for exit or disposal activities initiated after December 31, 2002.

In July 2002, the Emerging Issues Task Force (EITF) issued EITF Issues No. 02-3, Recognition and Reporting Gains and Losses on Energy Trading Contracts under EITF Issues No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, and No. 00-17, Measuring the Fair Value of Energy-Related Contracts in Applying Issue No. 98-10 (EITF 02-3). EITF 02-3 provides that all mark-to-market gains and losses on energy trading contracts should be shown net in the income statement whether or not settled physically. An entity should disclose the gross transaction volumes for those energy trading contracts that are physically settled. These provisions of EITF 02-3 are effective for interim and annual financial statements issued for periods ending after July 15, 2002. Our adoption of this provision will have a material impact on the presentation of our operating revenues and cost of gas as a result of presenting our energy trading activities net in the income statement. This income statement presentation change will not affect net income. In addition, under EITF 02-3 entities involved in energy trading activities are required to disclose all of the following: (1) the applicability of EITF 98-10; (2) the types of contracts that are accounted for as energy trading contracts; (3) the fair values of its energy trading contracts, aggregated by source or method of estimating fair value and by maturity dates of contracts; (4) a description of the methods and significant assumptions used to estimate fair value of its various classes of energy trading contracts; (5) a reconciliation of the beginning and ending carrying values for similarly aggregated trading contracts; and (6) the sensitivity of its estimates to changes in the near term. These disclosure provisions of EITF 02-3 are effective for financial statements issued for fiscal years ending after July 15, 2002. Also, EITF 02-3 discusses whether recognition of unrealized gains and losses at inception of energy trading contracts is appropriate in the absence of quoted market prices or current market transactions for contracts with similar terms. The EITF has not reached a consensus on this issue. Resolutions of this issue may have a material impact on the application of mark-to-market accounting for energy trading contracts.

Other

Southwest Gas Corporation. Information related to the termination of our proposed acquisition of Southwest Gas Corporation is presented in Note E in the Notes to the Consolidated Financial Statements and Part II, Item 1 of this Form 10-Q.

Item 4. Controls and Procedures

Within the 90 days prior to the filing date of this Amendment No. 1 to the Quarterly Report on Form 10-Q, we carried out an evaluation, under supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in timely alerting them to material information required to be disclosed by us in our periodic reports to the Securities and Exchange Commission. There have been no significant changes in our internal controls or in other factors that could significantly affect our disclosure controls subsequent to the date of their evaluation.

Exhibits

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

Exhibit No.	Exhibit Description
99.1	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.
99.2	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.

Signatures

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: November 12, 2002 By: /s/ Jim Kneale

Jim Kneale
Senior Vice President, Treasurer and
Chief Financial Officer
(Principal Financial Officer)

Certification

I, David L. Kyle, certify that:

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

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

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

4. The registrant s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;
b) evaluated the effectiveness of the registrant s disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the Evaluation Date); and
c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant s other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant s auditors and the audit committee of registrant s board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant s ability to record, process, summarize and report financial data and have identified for the registrant s auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant s internal controls; and

6. The registrant s other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 12, 2002

/s/ David L. Kyle
Chief Executive Officer

Certification

I, Jim Kneale, certify that:

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

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

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

4. The registrant s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

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

b) evaluated the effectiveness of the registrant s disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the Evaluation Date); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant s other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant s auditors and the audit committee of registrant s board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant s ability to record, process, summarize and report financial data and have identified for the registrant s auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant s internal controls; and

6. The registrant s other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 12, 2002

/s/ Jim Kneale
Chief Financial Officer