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

FORM 10-Q

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2005

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ____to____

Commission File Number: 1-12579

OGE ENERGY CORP.

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1481638**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

321 North Harvey
P.O. Box 321
Oklahoma City, Oklahoma 73101-0321
(Address of principal executive offices)
(Zip Code)

405-553-3000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes_X_ No____

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

As of June 30, 2005, 90,300,407 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED JUNE 30, 2005

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	**June 30, 2005**	December 31, 2004
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 26.1**	$ 26.4
Accounts receivable, less reserve of $3.5 and $4.5, respectively	**417.5**	487.9
Accrued unbilled revenues	**78.2**	45.5
Fuel inventories	**52.5**	89.0
Materials and supplies, at average cost	**55.4**	53.2
Price risk management	**135.4**	118.6
Gas imbalances	**129.2**	100.1
Accumulated deferred tax assets	**13.8**	13.7
Fuel clause under recoveries	**38.2**	54.3
Recoverable take or pay gas charges	**13.4**	17.0
Other	**5.2**	13.5
Total current assets	**964.9**	1,019.2
OTHER PROPERTY AND INVESTMENTS, at cost	**32.1**	31.4
PROPERTY, PLANT AND EQUIPMENT		
In service	**6,072.9**	5,957.6
Construction work in progress	**112.8**	110.5
Other	**5.0**	5.8
Total property, plant and equipment	**6,190.7**	6,073.9
Less accumulated depreciation	**2,555.2**	2,492.9
Net property, plant and equipment	**3,635.5**	3,581.0
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**30.5**	30.9
Intangible asset - unamortized prior service cost	**38.0**	38.0
Prepaid benefit obligation	**96.8**	92.7
Price risk management	**29.1**	19.6
McClain Plant expenses	**24.5**	11.0
Unamortized loss on reacquired debt	**20.4**	21.0
Unamortized debt issuance costs	**9.7**	10.2
Other	**13.9**	15.3
Total deferred charges and other assets	**262.9**	238.7

TOTAL ASSETS	**$ 4,895.4**	$ 4,870.3

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)
(Unaudited)

(In millions)	**June 30, 2005**	December 31, 2004
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 222.7**	$ 125.0
Accounts payable	**388.5**	476.2
Dividends payable	**30.0**	29.9
Customers' deposits	**46.7**	48.3
Accrued taxes	**27.2**	14.1
Accrued interest	**32.7**	33.2
Tax collections payable	**9.8**	7.2
Accrued vacation	**19.1**	17.9
Long-term debt due within one year	**0.8**	35.1
Non-recourse debt of joint venture	**1.2**	1.2
Price risk management	**109.3**	102.9
Gas imbalances	**25.0**	22.8
Provision for payments of take or pay gas	**17.4**	21.0
Other	**39.0**	40.6
Total current liabilities	**969.4**	975.4
LONG-TERM DEBT		
Long-term debt	**1,380.1**	1,385.1
Non-recourse debt of joint venture	**38.4**	39.0
Total long-term debt	**1,418.5**	1,424.1
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**203.9**	197.0
Accumulated deferred income taxes	**829.5**	802.0
Accumulated deferred investment tax credits	**34.3**	36.8
Accrued removal obligations, net	**120.2**	122.2
Price risk management	**25.0**	6.6
Asset retirement obligation	**1.1**	1.1
Other	**16.2**	19.5
Total deferred credits and other liabilities	**1,230.2**	1,185.2
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**708.7**	700.8
Retained earnings	**643.6**	659.8
Accumulated other comprehensive loss, net of tax	**(75.0)**	(75.0)
Total stockholders' equity	**1,277.3**	1,285.6
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 4,895.4**	$ 4,870.3

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		**Six Months Ended June 30,**	
(In millions, except per share data)	**2005**	2004	**2005**	2004
OPERATING REVENUES				
Electric Utility operating revenues	**$ 394.1**	$ 411.5	**$ 695.1**	$ 715.8
Natural Gas Pipeline operating revenues	**950.6**	743.9	**1,930.4**	1,481.3
Total operating revenues	**1,344.7**	1,155.4	**2,625.5**	2,197.1
COST OF GOODS SOLD				
Electric Utility cost of goods sold	**204.1**	230.6	**367.2**	402.0
Natural Gas Pipeline cost of goods sold	**895.0**	688.0	**1,822.6**	1,371.5
Total cost of goods sold	**1,099.1**	918.6	**2,189.8**	1,773.5
Gross margin on revenues	**245.6**	236.8	**435.7**	423.6
Other operation and maintenance	**101.8**	93.1	**200.7**	184.2
Depreciation	**45.2**	44.2	**91.8**	90.2
Taxes other than income	**17.2**	17.0	**35.8**	35.7
OPERATING INCOME	**81.4**	82.5	**107.4**	113.5
OTHER INCOME (EXPENSE)				
Other income	**0.9**	2.6	**2.6**	5.4
Other expense	**(1.0)**	(1.5)	**(3.0)**	(3.0)
Net other income (expense)	**(0.1)**	1.1	**(0.4)**	2.4
INTEREST INCOME (EXPENSE)				
Interest income	**0.2**	0.5	**2.2**	0.9
Interest on long-term debt	**(20.9)**	(18.9)	**(41.1)**	(37.1)
Interest expense - unconsolidated affiliate	**---**	(4.3)	**---**	(8.6)
Allowance for borrowed funds used during construction	**0.7**	0.2	**1.3**	0.3
Interest on short-term debt and other interest charges	**(1.7)**	(1.0)	**(3.3)**	(2.1)
Net interest expense	**(21.7)**	(23.5)	**(40.9)**	(46.6)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**59.6**	60.1	**66.1**	69.3
INCOME TAX EXPENSE	**21.1**	21.1	**22.3**	20.5
INCOME FROM CONTINUING OPERATIONS	**38.5**	39.0	**43.8**	48.8
DISCONTINUED OPERATIONS				
Income from discontinued operations	**---**	---	**---**	0.7
Income tax expense	**---**	---	**---**	0.3
Income from discontinued operations	**---**	---	**---**	0.4
NET INCOME	**$ 38.5**	$ 39.0	**$ 43.8**	$ 49.2
BASIC AVERAGE COMMON SHARES OUTSTANDING	**90.2**	87.6	**90.1**	87.6
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**90.8**	88.2	**90.6**	88.1
BASIC EARNINGS PER AVERAGE COMMON SHARE				
Income from continuing operations	**$ 0.43**	$ 0.44	**$ 0.49**	$ 0.55
Income from discontinued operations, net of tax	**---**	---	**---**	0.01
NET INCOME	**$ 0.43**	$ 0.44	**$ 0.49**	$ 0.56
DILUTED EARNINGS PER AVERAGE COMMON SHARE				
Income from continuing operations	**$ 0.42**	$ 0.44	**$ 0.48**	$ 0.55
Income from discontinued operations, net of tax	**---**	---	**---**	0.01
NET INCOME	**$ 0.42**	$ 0.44	**$ 0.48**	$ 0.56
DIVIDENDS DECLARED PER SHARE	**$ 0.3325**	$ 0.3325	**$ 0.6650**	$ 0.6650

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	**Six Months Ended June 30, 2005**	Six Months Ended June 30, 2004
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	**$ 43.8**	$ 49.2
Adjustments to reconcile net income to net cash provided from operating activities		
Income from discontinued operations	---	(0.4)
Depreciation	**91.8**	90.2
Deferred income taxes and investment tax credits, net	**25.6**	(0.5)
Gain on sale of assets	**(0.2)**	(3.1)
Price risk management assets	**(30.6)**	(23.7)
Price risk management liabilities	**24.2**	33.2
Other assets	**(11.8)**	(35.1)
Other liabilities	**(4.8)**	8.2
Change in certain current assets and liabilities		
Accounts receivable, net	**70.4**	(40.1)
Accrued unbilled revenues	**(32.7)**	(28.2)
Fuel, materials and supplies inventories	**34.3**	43.7
Gas imbalance asset	**(29.1)**	32.9
Fuel clause under recoveries	**16.1**	(5.3)
Other current assets	**11.9**	8.0
Accounts payable	**(87.7)**	63.0
Customers' deposits	**(1.6)**	2.4
Accrued taxes	**13.1**	23.2
Accrued interest	**(0.5)**	---
Gas imbalance liability	**2.2**	8.2
Fuel clause over recoveries	---	(32.4)
Other current liabilities	**(1.4)**	(3.6)
Net Cash Provided from Operating Activities	**133.0**	189.8
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	**(144.5)**	(122.5)
Proceeds from sale of assets	**0.7**	5.5
Other investing activities	---	0.7
Net Cash Used in Investing Activities	**(143.8)**	(116.3)
CASH FLOWS FROM FINANCING ACTIVITIES		
Retirement of long-term debt	**(35.3)**	(19.0)
Increase (decrease) in short-term debt, net	**97.7**	(202.5)
Premium on issuance of common stock	**7.9**	4.9
Contribution from minority interest	**0.1**	---
Dividends paid on common stock	**(59.9)**	(58.2)
Net Cash Provided from (Used in) Financing Activities	**10.5**	(274.8)
DISCONTINUED OPERATIONS		
Net cash provided from operating activities	---	0.4
Net Cash Provided from Discontinued Operations	---	0.4
NET DECREASE IN CASH AND CASH EQUIVALENTS	**(0.3)**	(200.9)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**26.4**	245.6
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 26.1**	$ 44.7

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Significant Accounting Policies

Organization

OGE Energy Corp. (collectively, with its subsidiaries, the "Company") is an energy and energy services provider offering physical delivery and management of both electricity and natural gas primarily in the south central United States. The Company conducts these activities through two business segments, the Electric Utility and the Natural Gas Pipeline segments. All significant intercompany transactions have been eliminated in consolidation.

The Electric Utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through Oklahoma Gas and Electric Company ("OG&E") and are subject to regulation by the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). OG&E was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries ("Enogex") and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership ("NOARK"), Enogex also owns a controlling interest in and operates Ozark Gas Transmission, L.L.C. ("OGT"), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex also holds a majority interest in Enerven Compression Services, LLC, a joint venture focused on the rental of natural gas compression assets. Enogex's participating entity in the joint venture, Enogex Compression Company, LLC ("Enogex Compression"), has been consolidated in the Company's financial statements with a minority interest recorded.

The Company allocates operating costs to its affiliates based on several factors. Operating costs directly related to specific affiliates are assigned to those affiliates. Where more than one affiliate benefits from certain expenditures, the costs are shared between those affiliates receiving the benefits. Operating costs incurred for the benefit of all affiliates are allocated among the affiliates, based primarily upon head-count, occupancy, usage or the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, operating income and assets. The Company believes this method provides a reasonable basis for allocating common expenses.

Basis of Presentation

The Condensed Consolidated Financial Statements included herein have been prepared by the Company, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been condensed or omitted pursuant to such rules and regulations; however, the Company believes that the disclosures are adequate to prevent the information presented from being misleading.

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at June 30, 2005 and December 31, 2004, the results of its operations for the three and six months ended June 30, 2005 and 2004, and the results of its cash flows for the six months ended June 30, 2005 and 2004, have been included and are of a normal recurring nature.

Due to seasonal fluctuations and other factors, the operating results for the three and six months ended June 30, 2005 are not necessarily indicative of the results that may be expected for the year ending December 31, 2005 or for any future period. The Condensed Consolidated Financial Statements and Notes thereto should be read in conjunction with the audited Consolidated Financial Statements and Notes thereto included in the Company's Form 10-K for the year ended December 31, 2004.

Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to the accounting principles prescribed by the Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 provides that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment. Excluding recoverable take or pay gas charges and the McClain Plant expenses (operating and maintenance expenses, depreciation, ad valorem taxes and interest on debt) in the table below, regulatory assets are being amortized and reflected in rates charged to customers over periods of up to 30 years.

OG&E records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates.

The following table is a summary of OG&E's regulatory assets and liabilities at:

(In millions)	**June 30, 2005**	December 31, 2004
Regulatory Assets		
Fuel clause under recoveries	$ **38.2**	$ 54.3

Income taxes recoverable from customers, net		**30.5**		30.9
McClain Plant expenses		**24.5**		11.0
Unamortized loss on reacquired debt		**20.4**		21.0
Recoverable take or pay gas charges		**13.4**		17.0
Arkansas transition costs		**0.1**		0.7
January 2002 ice storm		---		1.8
Miscellaneous		**1.0**		0.6
Total Regulatory Assets	**$**	**128.1**	$	137.3
Regulatory Liabilities				
Accrued removal obligations, net	**$**	**120.2**	$	122.2
Estimated refund on gas transportation and storage case		**9.0**		6.9
Estimated refund on FERC fuel		**1.0**		1.0
Total Regulatory Liabilities	**$**	**130.2**	$	130.1

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is reduced or written off, as appropriate. If the Company were required to discontinue the application of SFAS No. 71 for some or all of its operations, it could result in writing off the related regulatory assets; the financial effects of which could be significant.

Income Taxes

The Company files consolidated income tax returns. Income taxes are allocated to each affiliate based on its separate taxable income or loss. Federal investment tax credits on electric utility property have been deferred and are being amortized to income over the life of the related property. Amortization of the federal investment tax credits was approximately $1.3 million for each of the three month periods ended June 30, 2005 and 2004 and was approximately $2.6 million for each of the six month periods ended June 30, 2005 and 2004 and are recorded as income tax benefits in the Condensed Consolidated Statements of Income.

The Company follows the provisions of SFAS No. 109, "Accounting for Income Taxes," which uses an asset and liability approach to accounting for income taxes. Under SFAS No. 109, deferred tax assets or liabilities are computed based on the difference between the financial statement and income tax bases of assets and liabilities using the enacted marginal tax rate. Deferred income tax expenses or benefits are based on the changes in the asset or liability from period to period.

OG&E has an Oklahoma investment tax credit ("ITC") carryover of approximately $5.5 million. These ITC carryover amounts will begin expiring in the year 2017. During 2005, additional investment tax credits of approximately $3.8 million are expected to be generated. OG&E believes that, based on current projections, the full $9.3 million of these ITC amounts will be fully utilized in 2006.

In June 2005, the Company filed amended Oklahoma and Arkansas state income tax returns for the years 1993 through 2003. The returns were filed to reflect changes resulting from Internal Revenue Service audit adjustments as well as additional Oklahoma investment tax credits for assets placed into service prior to 2001. The Company anticipates receiving approximately $2.3 million of Oklahoma investment tax credit refunds and approximately $1.5 million of state income tax refunds by the end of 2005.

Stock-Based Compensation

Pursuant to the provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," the Company has elected to continue using the intrinsic value method of accounting for its stock-based employee compensation plans in accordance with Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees." Accordingly, the Company has not recognized compensation expense for its stock-based awards to employees. The Company will adopt SFAS No. 123 (Revised), "Share-Based Payment," effective January 1, 2006, which will require the Company to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. The following table reflects pro forma net income and income per average common share had the Company elected to adopt the fair value based method of SFAS No. 123:

	Three Months Ended June 30,				**Six Months Ended June 30,**			
(In millions, except per share data)		**2005**		2004		**2005**		2004
Net income, as reported	**$**	**38.5**	$	39.0	**$**	**43.8**	$	49.2
Add:								
Stock-based employee compensation expense included in reported net income, net of related tax effects		---		---		---		---
Deduct:								
Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects		**0.2**		0.3		**0.3**		0.7
Pro forma net income	**$**	**38.3**	$	38.7	**$**	**43.5**	$	48.5

Income per average common share								
Basic - as reported	**$**	**0.43**	$	0.44	**$**	**0.49**	$	0.56
Diluted - as reported	**$**	**0.42**	$	0.44	**$**	**0.48**	$	0.56
Basic - pro forma	**$**	**0.42**	$	0.44	**$**	**0.48**	$	0.55
Diluted - pro forma	**$**	**0.42**	$	0.44	**$**	**0.48**	$	0.55

Reclassifications

Certain prior year amounts have been reclassified on the consolidated financial statements to conform to the 2005 presentation.

2. Accounting Pronouncement

In June 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections," which replaces APB Opinion No. 20, "Accounting Changes" and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." SFAS No. 154 applies to all voluntary changes in accounting principle and requires retrospective application to prior periods' financial statements of changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. Adoption of SFAS No. 154 is required for accounting changes and error corrections made in fiscal years beginning after December 15, 2005. The Company will adopt this new standard effective January 1, 2006.

3. Accumulated Other Comprehensive Loss

The components of total comprehensive income for the three and six months ended June 30, 2005 and 2004, respectively, are as follows:

	Three Months Ended June 30,				**Six Months Ended June 30,**			
(In millions)		**2005**		2004		**2005**		2004
Net income	**$**	**38.5**	$	39.0	**$**	**43.8**	$	49.2
Other comprehensive income (loss), net of tax:								
Deferred hedging gains (losses), net of tax		**1.7**		(0.2)		**(0.1)**		(0.2)
Amortization of cash flow hedge, net of tax		**---**		---		**0.1**		---
Reversal of unrealized gains on available-for-sale securities		**---**		---		**---**		(0.4)
Total comprehensive income	**$**	**40.2**	$	38.8	**$**	**43.8**	$	48.6

The components of accumulated other comprehensive loss at June 30, 2005 and December 31, 2004 are as follows:

(In millions)		**June 30, 2005**		December 31, 2004
Minimum pension liability adjustment, net of tax	**$**	**(72.7)**	$	(72.7)
Deferred hedging gains, net of tax		**0.1**		0.2
Settlement and amortization of cash flow hedge, net of tax		**(2.4)**		(2.5)
Total accumulated other comprehensive loss	**$**	**(75.0)**	$	(75.0)

Accumulated other comprehensive loss at both June 30, 2005 and December 31, 2004 included an after tax loss of approximately $72.7 million ($118.6 million pre-tax) related to a minimum pension liability adjustment based on a review of the funded status of the Company's pension plan by the Company's actuarial consultants as of December 31, 2004. Any increases or decreases in the minimum pension liability will be reflected in Other Comprehensive Income or Loss in the fourth quarter.

4. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affect recognized assets and liabilities but which do not result in cash receipts or payments.

	Six Months Ended June 30,			
(In millions)		**2005**		2004
NON-CASH INVESTING AND FINANCING ACTIVITIES				
Change in fair value of long-term debt due to interest rate swaps	**$**	**(4.0)**	$	(6.0)

5. Common Stock

For the three and six months ended June 30, 2005, respectively, there were 105,298 and 336,966 shares of new common stock issued pursuant to the Company's Stock Incentive Plan, related to exercised stock options.

6. Earnings Per Share

Outstanding shares for purposes of basic and diluted earnings per average common share were calculated as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2005**	2004	**2005**	2004
Average Common Shares Outstanding				
Basic average common shares outstanding	**90.2**	87.6	**90.1**	87.6
Effect of dilutive securities:				
Employee stock options and unvested stock grants	**0.3**	0.3	**0.2**	0.2
Contingently issuable shares (performance units)	**0.3**	0.3	**0.3**	0.3
Diluted average common shares outstanding	**90.8**	88.2	**90.6**	88.1

Approximately 0.3 million shares for each of the three and six month periods ended June 30, 2005 and approximately 0.7 million shares for each of the three and six month periods ended June 30, 2004, related to outstanding employee stock options, were not included in the calculation of diluted earnings per average common share because the effect of including those shares is anti-dilutive as the exercise price of the stock options exceeded the average common stock market price during the respective period.

7. Long-Term Debt

At June 30, 2005, the Company is in compliance with all of its debt agreements.

Long-Term Debt with Optional Redemption Provisions

OG&E has three series of variable rate industrial authority bonds (the "Bonds") with optional redemption provisions that allow the holders to request repayment of the Bonds at various dates prior to the maturity. The Bonds, which can be tendered at the option of the holder during the next 12 months, are as follows:

SERIES	DATE DUE	AMOUNT
Variable %	Garfield Industrial Authority, January 1, 2025	$ **47.0**
Variable %	Muskogee Industrial Authority, January 1, 2025	**32.4**
Variable %	Muskogee Industrial Authority, June 1, 2027	**56.0**
	Total (redeemable during next 12 months)	**$ 135.4**

All of these Bonds are subject to an optional tender at the request of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase. The bond holders, on any business day, can request repayment of the Bond by delivering an irrevocable notice to the tender agent stating the principal amount of the Bond, payment instructions for the purchase price and the business day the Bond is to be purchased. The repayment option may only be exercised by the holder of a Bond for the principal amount. When a tender notice has been received by the trustee, a third party remarketing agent for the Bonds will attempt to remarket any Bonds tendered for purchase. This process occurs once per week. Since the original issuance of these series of Bonds in 1995 and 1997, the remarketing agent has successfully remarketed all tendered bonds. If the remarketing agent is unable to remarket any such Bonds, the Company is obligated to repurchase such unremarketed Bonds. The Company has sufficient liquidity to meet these obligations.

Interest Rate Swap Agreement

Fair Value Hedge

At June 30, 2005, OG&E had one outstanding interest rate swap agreement that qualified as a fair value hedge, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate ("LIBOR"). The objective of this interest rate swap was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. This interest rate swap qualified as a fair value hedge under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

On April 1, 2005, Enogex terminated two interest rate swap agreements (with a total notional amount of $200 million) and received approximately $0.2 million related to this transaction. Since inception of the Enogex interest rate swap agreements, which converted $200 million of 8.125 percent fixed rate debt due January 15, 2010 to a floating rate based upon the three and six month LIBOR, the Company has paid approximately $81.3 million in interest and has received approximately $29.9 million related to these agreements. The effective interest rate until maturity will be approximately 7.67 percent on this long-term debt.

At June 30, 2005 and December 31, 2004, the fair value pursuant to OG&E's interest rate swap was approximately $3.9 million and the fair value hedge was classified as Deferred Charges and Other Assets – Price Risk Management in the Condensed Consolidated Balance Sheets. A corresponding net increase of approximately $3.9 million was reflected in Long-Term Debt at June 30, 2005 and December 31, 2004 as this fair value hedge was effective at June 30, 2005 and December 31, 2004.

Debt Issuance

OG&E's 7.125 percent $110 million long-term debt series matures on October 15, 2005. OG&E currently expects to replace this maturing debt with new debt later this year.

8. Short-Term Debt

The short-term debt balance was approximately $222.7 million and $125.0 million at June 30, 2005 and December 31, 2004, respectively. The following table shows the Company's lines of credit in place, commercial paper outstanding and available cash at June 30, 2005. At June 30, 2005, the Company's short-term borrowings consisted of borrowings on its revolving credit agreement and commercial paper.

Lines of Credit, Commercial Paper and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding	Maturity
OGE Energy Corp.	$ 15.0	$ ---	April 6, 2006 (A)
OG&E (B)	100.0	---	October 20, 2009 (C)
OGE Energy Corp. (D)	450.0	222.7	October 20, 2009 (C)
	565.0	222.7	
Cash	26.1	N/A	N/A
Total	$ 591.1	$ 222.7	

(A) In April 2005, the Company renewed its $15.0 million credit facility, shown in the table above, which matures April 6, 2006.
(B) No borrowings were outstanding at June 30, 2005 under this line of credit; however, $0.2 million of this line of credit supports a letter of credit.
(C) Each of the credit facilities has a five-year term with two options to extend the term for one year.
(D) This bank facility is available to back up a maximum of $300.0 million of the Company's commercial paper borrowings and can be used as a letter of credit facility. At June 30, 2005, the Company had approximately $85.0 million in outstanding borrowings under this line of credit and approximately $137.7 million in commercial paper borrowings.

The Company's and OG&E's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Their respective back-up lines of credit contain pricing grids based on our credit ratings that cause annual fees and borrowing rates to increase if they suffer an adverse ratings impact. The impact of any future downgrades would result in an increase in the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes.

Unlike the Company and Enogex, OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time for a two-year period beginning January 1, 2005 and ending December 31, 2006.

9. Retirement Plans and Postretirement Benefit Plans

In December 2003, the FASB issued SFAS No. 132 (Revised), "Employer's Disclosures about Pension and Postretirement Benefits, an amendment of FASB Statements No. 87, 88 and 106," which revised the disclosure requirements applicable to employers' pension plans and other postretirement benefit plans. This Statement requires additional disclosures for defined benefit pension plans and other defined benefit postretirement plans, including disclosures describing the components of net periodic benefit cost recognized during interim periods. The details of net periodic benefit cost of the pension plan (including the restoration of retirement income plan) and the postretirement benefit plans included in the Condensed Consolidated Financial Statements are as follows:

Net Periodic Benefit Cost

	Pension Plan and Restoration of Retirement Income Plan			
	Three Months Ended June 30,		**Six Months Ended June 30,**	
(In millions)	**2005**	2004	**2005**	2004
Service cost	**$ 4.7**	$ 4.2	**$ 9.5**	$ 8.4
Interest cost	**7.6**	7.4	**15.2**	14.8
Return on plan assets	**(8.6)**	(7.9)	**(17.1)**	(15.8)
Amortization of net loss	**3.8**	3.0	**7.4**	6.0
Amortization of unrecognized prior service cost	**1.5**	1.6	**3.1**	3.2
Net periodic benefit cost	**$ 9.0**	$ 8.3	**$ 18.1**	$ 16.6

	Postretirement Benefit Plans

(In millions)	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Service cost	**$ 0.8**	$ 0.7	**$ 1.6**	$ 1.5
Interest cost	**2.6**	2.7	**5.2**	5.5
Return on plan assets	**(1.4)**	(1.4)	**(2.8)**	(2.8)
Amortization of transition obligation	**0.7**	0.7	**1.4**	1.4
Amortization of net loss	**1.3**	1.3	**2.6**	2.5
Amortization of unrecognized prior service cost	**0.5**	0.5	**1.0**	1.0
Net periodic benefit cost	**$ 4.5**	$ 4.5	**$ 9.0**	$ 9.1

Pension Plan Funding

The Company plans to contribute approximately $32.0 million in 2005 to its pension plan, which represents the Company's 2004 pension expense. During the second quarter of 2005, the Company funded approximately $21.3 million to the pension plan. The remaining expected contributions to the pension plan in 2005, anticipated to be in the form of cash in the third quarter, are discretionary contributions and are not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

10. Report of Business Segments

The Company's Electric Utility operations are conducted through OG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy. The Company's Natural Gas Pipeline operations are conducted through Enogex. Enogex is engaged in the transportation and storage of natural gas, the gathering and processing of natural gas and the marketing of natural gas. Other Operations for the three and six months ended June 30, 2005 primarily includes unallocated corporate expenses, interest expense on commercial paper and interest expense on long-term debt. Other Operations for the three and six months ended June 30, 2004 primarily includes unallocated corporate expenses, interest expense to unconsolidated affiliate and interest expense on commercial paper. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. The following tables summarize the results of the Company's business segments for the three and six months ended June 30, 2005 and 2004.

Three Months Ended June 30, 2005 (In millions)	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
Operating revenues	**$ 394.1**	**$ 983.3**	**$ ---**	**$ (32.7)**	**$ 1,344.7**
Cost of goods sold	**215.9**	**915.8**	**---**	**(32.6)**	**1,099.1**
Gross margin on revenues	**178.2**	**67.5**	**---**	**(0.1)**	**245.6**
Other operation and maintenance	**79.7**	**25.0**	**(2.9)**	**---**	**101.8**
Depreciation	**31.4**	**11.6**	**2.2**	**---**	**45.2**
Taxes other than income	**12.1**	**4.3**	**0.8**	**---**	**17.2**
Operating income (loss)	**55.0**	**26.6**	**(0.1)**	**(0.1)**	**81.4**
Other income	**0.3**	**0.5**	**0.1**	**---**	**0.9**
Other expense	**(0.3)**	**(0.1)**	**(0.6)**	**---**	**(1.0)**
Interest income	**---**	**0.6**	**0.2**	**(0.6)**	**0.2**
Interest expense	**(9.7)**	**(9.4)**	**(3.4)**	**0.6**	**(21.9)**
Income tax expense (benefit)	**15.6**	**6.9**	**(1.4)**	**---**	**21.1**
Net income (loss)	**$ 29.7**	**$ 11.3**	**$ (2.4)**	**$ (0.1)**	**$ 38.5**

(A) Natural Gas Pipeline's operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

Three Months Ended June 30, 2005 (In millions)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	**$ 78.8**	**$ 161.7**	**$ 887.0**	**$ (144.2)**	**$ 983.3**
Operating income (loss)	**$ 12.8**	**$ 16.2**	**$ (2.4)**	**$ ---**	**$ 26.6**

Three Months Ended June 30, 2004	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 411.5	$ 775.5	$ ---	$ (31.6)	$ 1,155.4
Cost of goods sold	242.9	707.3	---	(31.6)	918.6
Gross margin on revenues	168.6	68.2	---	---	236.8
Other operation and maintenance	71.5	25.1	(3.5)	---	93.1
Depreciation	30.3	11.4	2.5	---	44.2
Taxes other than income	11.8	4.4	0.8	---	17.0
Operating income	55.0	27.3	0.2	---	82.5
Other income	0.6	1.8	0.2	---	2.6
Other expense	(0.7)	---	(0.8)	---	(1.5)
Interest income	---	0.4	0.5	(0.4)	0.5
Interest expense	(9.6)	(10.1)	(4.7)	0.4	(24.0)
Income tax expense (benefit)	14.9	7.9	(1.7)	---	21.1
Net income (loss)	$ 30.4	$ 11.5	$ (2.9)	$ ---	$ 39.0

(A) Natural Gas Pipeline’s operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

Three Months Ended June 30, 2004	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 86.5	$ 124.6	$ 687.9	$ (123.5)	$ 775.5
Operating income (loss)	$ 17.1	$ 10.3	$ (0.1)	$ ---	$ 27.3

Six Months Ended June 30, 2005	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 695.1**	**$ 1,984.1**	**$ ---**	**$ (53.7)**	**$ 2,625.5**
Cost of goods sold	**390.9**	**1,853.4**	**---**	**(54.5)**	**2,189.8**
Gross margin on revenues	**304.2**	**130.7**	**---**	**0.8**	**435.7**
Other operation and maintenance	**157.1**	**49.5**	**(5.9)**	**---**	**200.7**
Depreciation	**64.5**	**23.3**	**4.0**	**---**	**91.8**
Taxes other than income	**24.8**	**9.1**	**1.9**	**---**	**35.8**
Operating income	**57.8**	**48.8**	**---**	**0.8**	**107.4**
Other income	**1.0**	**0.5**	**1.1**	**---**	**2.6**
Other expense	**(0.8)**	**(0.5)**	**(1.7)**	**---**	**(3.0)**
Interest income	**1.6**	**1.2**	**0.5**	**(1.1)**	**2.2**
Interest expense	**(19.4)**	**(18.5)**	**(6.3)**	**1.1**	**(43.1)**
Income tax expense (benefit)	**12.2**	**12.1**	**(2.4)**	**0.4**	**22.3**
Net income (loss)	**$ 28.0**	**$ 19.4**	**$ (4.0)**	**$ 0.4**	**$ 43.8**

(A) Natural Gas Pipeline’s operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

Six Months Ended June 30, 2005	Transportation and	Gathering and	Marketing (B)	Eliminations	Total

	Storage	Processing			
(In millions)					
Operating revenues	**$ 148.5**	**$ 314.5**	**$ 1,790.7**	**$ (269.6)**	**$ 1,984.1**
Operating income (loss)	**$ 25.6**	**$ 29.6**	**$ (6.4)**	**$ ---**	**$ 48.8**

(B) In March 2005, Enogex corrected its procedure for accounting for park and loan transactions (natural gas storage transactions) during 2004 that resulted from an incorrect change in an accounting procedure implemented during 2004. The incorrect procedure affected the timing of recognition of revenue and income from park and loan transactions and resulted in a temporary overstatement of operating revenues without the associated expense until the transaction was completed and the expense recognized. As a result of this correction, Enogex recorded a pre-tax charge of approximately $7.7 million as a reduction in Operating Revenues in the Condensed Consolidated Statement of Income and a corresponding $7.7 million decrease in Current Price Risk Management Assets in the Condensed Consolidated Balance Sheet during the three months ended March 31, 2005.

Six Months Ended June 30, 2004	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 715.8	$ 1,524.7	$ ---	$ (43.4)	$ 2,197.1
Cost of goods sold	426.1	1,390.8	---	(43.4)	1,773.5
Gross margin on revenues	289.7	133.9	---	---	423.6
Other operation and maintenance	143.0	48.4	(7.2)	---	184.2
Depreciation	62.2	22.9	5.1	---	90.2
Taxes other than income	24.5	9.3	1.9	---	35.7
Operating income	60.0	53.3	0.2	---	113.5
Other income	1.0	3.2	1.2	---	5.4
Other expense	(1.2)	(0.3)	(1.5)	---	(3.0)
Interest income	0.2	0.5	0.7	(0.5)	0.9
Interest expense	(19.3)	(19.4)	(9.3)	0.5	(47.5)
Income tax expense (benefit)	10.3	13.4	(3.2)	---	20.5
Income (loss) from continuing operations	30.4	23.9	(5.5)	---	48.8
Income from discontinued operations	---	0.4	---	---	0.4
Net income (loss)	$ 30.4	$ 24.3	$ (5.5)	$ ---	$ 49.2

(A) Natural Gas Pipeline's operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

Six Months Ended June 30, 2004	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 170.1	$ 257.9	$ 1,355.1	$ (258.4)	$ 1,524.7
Operating income (loss)	$ 31.6	$ 22.5	$ (0.8)	$ ---	$ 53.3

11. Commitments and Contingencies

Except as set forth below and in Note 12, the circumstances set forth in Note 17 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2004 and in Note 12 to the Company's Condensed Consolidated Financial Statements included in the Company's Form 10-Q for the quarter ended March 31, 2005, appropriately represent, in all material respects, the current status of any material commitments and contingent liabilities.

Natural Gas Measurement Case

As reported in Note 17 to the Company's Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2004 and in Note 12 to the Company's Form 10-Q for the quarter ended March 31, 2005, the Company has been involved in legal proceedings filed by Jack J. Grynberg in federal courts related to natural gas measurement. A ruling in this case by the special master was received in May 2005 which dismissed OG&E and all Enogex parties named in these proceedings. This ruling may be appealed.

Agreement with Colorado Interstate Gas Company

OGE Energy Resources, Inc. ("OERI") and Cheyenne Plains Gas Pipeline Company, L.L.C. are parties to a firm transportation services agreement dated April 14, 2004. The Cheyenne Plains Pipeline provides interstate gas transportation services in Wyoming, Colorado and Kansas with a capacity of 560,000 decatherms/day ("Dth/day"). OERI reserved 60,000 Dth/day of firm capacity on the Cheyenne Plains Pipeline for 10 years. Such reservation provides OERI access to significant additional natural gas supplies in the Rocky Mountain production basins. OERI pays a demand fee of approximately $7.5 million annually for this capacity. If current market conditions continue, OERI could incur a loss up to approximately $4.0 million in 2005 related to its Cheyenne Plains' position as a result of unfavorable market conditions for the capacity primarily due to the earlier than expected in-service date for the project and the associated lack of upstream gas supply and pipeline infrastructure to deliver gas to the Cheyenne hub for 2005. OERI incurred a loss of approximately $0.8 million and $1.8 million during the three and six months ended June 30, 2005, respectively, related to its Cheyenne Plains' position.

Pipeline Rupture

On May 10, 2005, a natural gas pipeline rupture occurred on an Enogex facility within the ANR Pipeline, Inc. ("ANR") plant site in Custer County, near Clinton, Oklahoma, resulting in an explosion and fire. Several companies have operations at the site which is operated by ANR, a subsidiary of El Paso Corporation. No injuries were reported as a result of the incident. The Enogex pipeline equipment at the site was isolated and the flow of gas to the site was shut off. Investigation of the incident and the cause thereof is ongoing. The site is near the location of the former Enogex Custer gas processing plant closed in 2002. Although temporarily disrupted, pipeline operations continue at the location. It is anticipated that any third party damages related to this incident will not be material to the Company as they will be covered by insurance following payment of the deductible, which deductible has been accrued in the Company's consolidated financial statements.

Environmental Laws and Regulations

OG&E

Air

While the United States has withdrawn its support of the Kyoto Protocol on global warming, legislation has been considered that would limit carbon dioxide ("CO2") emissions. In June 2005, Senators McCain and Lieberman attempted to attach a CO2 reduction requirement to the federal Energy Bill; however, this attempt failed. If legislation is passed requiring mandatory reductions, this could have a tremendous impact on all coal-fired electric utilities, including OG&E's operations by requiring OG&E to significantly reduce the use of coal as a fuel source.

On March 25, 2005, the Environmental Protection Agency ("EPA") issued the Clean Air Mercury Rule ("CAMR") to limit mercury emissions from coal-fired boilers. The CAMR requires reductions in mercury in two phases, phase I beginning in 2010 and phase II in 2018. The CAMR is based on the cap and trade program that will allow utilities to purchase mercury allowances (if available) rather than reduce emissions. It is anticipated that OG&E will need to obtain allowances or reduce its mercury emissions in Phase II by approximately 70 percent. The CAMR will also require continuous monitoring of mercury emissions from OG&E's coal-fired boilers beginning in 2009. The cost to OG&E of the CAMR has not yet been established because monitoring technology is still being developed. However, the cost to comply with the CAMR will be in addition to the cost of other emissions monitoring that is already in place pursuant to Title IV of the Clean Air Act Amendments of 1990.

In 1997, the EPA finalized revisions to the ambient ozone and fine particulate standards. After a court challenge, which delayed implementation, the EPA has now begun to finalize the implementation process. Based on the most recent monitoring data, the EPA has designated Oklahoma "in attainment" with both standards. However, on June 21 and 22, 2005, both Tulsa and Oklahoma City exceeded the 8-hour ozone standard. If Tulsa and Oklahoma City continue to exceed the ozone standard for the next three ozone seasons, they could face redesignation to non-attainment status. To help avoid redesignation, both Tulsa and Oklahoma City have entered into an "Early Action Compact" with the EPA whereby voluntary measures will be enacted to reduce ozone. Minimal impact on OG&E's operations is expected.

In July 1999, the EPA first issued regulations concerning regional haze. On June 15, 2005, the EPA issued final amendments to its 1999 rule. These regulations are intended to protect visibility in national parks and wilderness areas throughout the United States. In Oklahoma, the Wichita Mountains are the only area covered under the regulation. However, Oklahoma's impact on parks in other states must also be evaluated. Sulfates and nitrate aerosols (both emitted

from coal-fired boilers) can lead to the degradation of visibility. The state of Oklahoma has joined with eight other central states and has begun to finalize the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas. This study is expected to be completed and any compliance strategies adopted by January 2008. If an impact is determined and the regulations remain in effect, then significant capital expenditures could be required for both the Sooner and Muskogee generating stations.

On June 21, 2005 the Oklahoma Department of Environmental Quality ("ODEQ") adopted new regulations dealing with the emission of toxic air contaminants. It is anticipated at this time that the impact on OG&E will be minimal. However, if the ODEQ were to identify high concentrations of any toxic contaminants near OG&E facilities, significant expenses could be incurred.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Except as otherwise stated above, in Note 12 below, in Item 1 of Part II of this Form 10-Q, in Notes 12 and 13 of Notes to Condensed Consolidated Financial Statements in the Company's Form 10-Q for the quarter ended March 31, 2005, in Item 1 of Part II of that report, in Notes 17 and 18 of Notes to Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2004 and in Item 3 of that report, management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. This assessment of currently pending or threatened lawsuits is subject to change.

12. Rate Matters and Regulation

Except as set forth below, the circumstances set forth in Note 18 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2004 and in Note 13 to the Company's Condensed Consolidated Financial Statements included in the Company's Form 10-Q for the quarter ended March 31, 2005, appropriately represent, in all material respects, the current status of any regulatory matters.

Completed Regulatory Matters

2002 Settlement Agreement

On November 22, 2002, the OCC signed a rate order containing the provisions of a settlement of OG&E's rate case (the "Settlement Agreement"). The Settlement Agreement provides for, among other items: (i) a $25.0 million annual reduction in the electric rates of OG&E's Oklahoma customers which went into effect January 6, 2003; (ii) recovery by OG&E, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) OG&E to acquire electric generation of not less than 400 megawatts ("MW") ("New Generation") to be integrated into OG&E's generation system; and (iv) recovery by OG&E, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through OG&E's rider for sales to other utilities and power marketers ("off-system sales"). Previously, OG&E had a 50/50 sharing mechanism in Oklahoma for any off-system sales. The Settlement Agreement provided that the first $1.8 million in annual net profits from OG&E's off-system sales will go to OG&E, the next $3.6 million in annual net profits from off-system sales will go to OG&E's Oklahoma customers, and any net profits from off-system sales in excess of these amounts will be credited in each sales year with 80 percent to OG&E's Oklahoma customers and the remaining 20 percent to OG&E. During the six months ended June 30, 2005, OG&E recovered approximately $1.8 million in annual net profits from off-system sales. Including this amount, OG&E has recovered a total of $5.4 million related to the regulatory asset since December 31, 2002, which is in accordance with the Settlement Agreement. In April 2005, OG&E began crediting annual net profits from off-system sales to OG&E's Oklahoma customers up to $3.6 million and any annual net profits from off-system sales in excess of this amount will be shared between OG&E's Oklahoma customers and OG&E in accordance with the Settlement Agreement.

Acquisition of Power Plant

On July 9, 2004, OG&E completed the acquisition of NRG McClain LLC's 77 percent interest in the 520 MW NRG McClain Station (the "McClain Plant"). This transaction was intended to satisfy the requirement in the Settlement

Agreement to acquire New Generation. The McClain Plant, which includes natural gas-fired combined cycle combustion turbine units, is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority ("OMPA").

The closing of the purchase of the McClain Plant was subject to approval from the FERC. On July 2, 2004, the FERC authorized OG&E to acquire the McClain Plant. The FERC's approval was based on an offer of settlement in which OG&E proposed, among other things, to install certain new transmission facilities and to hire an independent market monitor to oversee OG&E's activity for a limited period. Two other parties, InterGen Services, Inc. and AES Shady Point ("AES"), opposed OG&E's offer of settlement and filed competing offers of settlement. In the July 2, 2004 order, the FERC: (i) approved OG&E's offer of settlement subject to conditions; (ii) rejected the competing offers of settlement; and (iii) approved OG&E's acquisition of the McClain Plant. As part of the July 2, 2004 order, OG&E agreed to undertake the following mitigation measures: (i) install a transformer at one of its facilities at a cost of approximately $9.3 million which was completed in the fourth quarter of 2004; (ii) provide a 600 MW bridge into its control area from the Redbud Energy LP ("Redbud") plant; and (iii) hire an independent market monitor to oversee OG&E's activity in its control area. The market monitoring plan is designed to detect any anticompetitive conduct by OG&E from operation of its generation resources or its transmission system. The market monitoring function is performed daily and periodic reviews are also performed. To date, the independent market monitor has filed three quarterly reports each covering the quarterly periods subsequent to the McClain Plant acquisition. The report covering the period from April 1, 2005 to June 30, 2005 has not been filed to date. Based on an analysis of transmission congestion data on OG&E's system, along with data on purchases and sales, generation dispatch data and power flows on OG&E's tie lines, the market monitor concluded that OG&E did not act in an anticompetitive manner through either dispatch of its generation or operation of its transmission system. Further, in the review of the disposition of requests for transmission service, the independent market monitor detected no problems with access to OG&E's transmission system. Additionally, OG&E's operations under the ongoing mitigation measures that require OG&E to make available transmission capability available to the Redbud power plant for access to the OG&E system were analyzed. Based on this analysis, the market monitor concluded that OG&E has complied with this requirement. OG&E completed the installation and implementation of these mitigation measures and notified the FERC in writing on May 31, 2005 that these were completed. OG&E's obligation to make available transmission capacity to the Redbud power plant was also terminated upon implementation of the mitigation measures. One party filed a request for rehearing of the FERC's July 2, 2004 order. On April 18, 2005, the FERC issued an order denying the party's request for rehearing. This party, who had 60 days to file a petition for review with the appropriate U.S. Court of Appeals, did not make a filing within this time period.

OG&E expects the addition of the McClain Plant, including the effects of an interim power purchase agreement OG&E had with NRG McClain LLC while OG&E was awaiting regulatory approval to complete the acquisition, will provide savings, over a three-year period, in excess of $75.0 million to its Oklahoma customers. In the event OG&E is unable to demonstrate at least $75.0 million in savings to its customers during this 36-month period, OG&E will be required to credit its Oklahoma customers any unrealized savings below $75.0 million as determined at the end of the 36-month period ending December 31, 2006. At this time, OG&E believes that it will be able to demonstrate at least $75.0 million in savings during this period.

Enogex FERC Section 311 2004 Rate Cases and related FERC dockets

On September 1, 2004, Enogex made a filing at the FERC to revise its previously approved Statement of Operating Conditions ("SOC") to permit, among other things, the unbundling, effective October 1, 2004, of its previously bundled gathering and transportation services. On and after October 1, 2004, the FERC will regulate Enogex's Section 311 transportation and any regulation of gathering will be pursuant to Oklahoma statute. Several parties challenged the SOC changes. On September 30, 2004, Enogex made its required triennial filing at the FERC to update its Section 311 maximum transportation rate. Various parties challenged certain aspects of the rate filing. In addition, on September 29, 2004, Enogex filed an updated fuel factor with the FERC for the last quarter of 2004. One party protested the fourth quarter 2004 fuel filing. Finally, on November 15, 2004, Enogex filed an updated fuel factor for fuel year 2005 (calendar year 2005). The filing is the annual filing made by Enogex that establishes the fixed fuel percentage for natural gas shipped on Enogex's system. One party challenged the annual fuel factor filing.

The FERC Staff and various intervenors served data requests on Enogex concerning the revised SOC, the rate filing and the two fuel filings. Enogex responded to the discovery. Three technical conferences were held in four dockets on January 13, 2005, March 30, 2005 and June 7-8, 2005. On June 8, 2005, the parties reached a settlement in principle resolving all issues in all four dockets. The parties are now engaged in the preparation of the settlement documents that

Enogex anticipates filing with the FERC in early August 2005. The FERC has no obligation to act on a settlement within a certain time period but it is the FERC's practice to act promptly on uncontested settlements.

OGT Spin Down

On January 19, 2005, OGT filed an application under section 7(b) of the Natural Gas Act ("NGA") for authority to remove from the FERC jurisdiction ("abandonment"), by transfer to its affiliate, Ozark Arkansas Gas Gathering, L.L.C. ("OAGG"), certain lateral pipeline and compression facilities in Oklahoma and Arkansas. The subject facilities have been performing a natural gas gathering function and were considered by OGT to no longer be needed to meet its interstate transportation obligations. The FERC agreed with OGT, determining that the subject facilities are non-jurisdictional gathering facilities exempt from the NGA regulation. Thus, pursuant to the FERC's order approving abandonment issued May 4, 2005 in Docket No. CP005-51-000, OGT's abandonment of facilities to OAGG became effective July 1, 2005. OAGG and Ozark Gas Gathering, L.L.C. ("OGG") also merged with OGG being the name of the merged entity. Full implementation of the abandonment, including the provision of gathering services to OGT's former customers by OGG, is underway.

Gas Transportation and Storage Agreement

As part of the Settlement Agreement, OG&E also agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. The prescribed bidding process detailed in the Settlement Agreement provided that separate transportation services be bid for each generation facility. OG&E believes that, in order for it to achieve maximum coal generation, to deliver the lowest cost energy to its customers and to ensure reliable electric service, it must have integrated, firm no-notice load following service for both gas transportation and gas storage. This type of service is required to permit natural gas units to satisfy the daily swings in customer demand placed on OG&E's system and not impede coal energy production. Accordingly, OG&E evaluated its competitive bid options in light of these circumstances. The study determined that the required integrated service is not available in the marketplace from parties other than Enogex. The study also indicated that non-integrated service would result in higher costs to customers. OG&E's evaluation clearly demonstrates that the Enogex integrated gas system provides superior integrated, firm no-notice load following service to OG&E that is not available from other companies serving the OG&E marketplace.

On April 29, 2003, as required by the Settlement Agreement, OG&E filed an application with the OCC in which OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of OG&E's natural gas-fired generation facilities. OG&E will pay Enogex annual demand fees of approximately $46.8 million for the right to transport specified maximum daily quantities ("MDQ") and maximum hourly quantities ("MHQ") of gas at various minimum gas delivery pressures depending on the operational needs of the individual generating facility. In addition, OG&E supplies system fuel in-kind for its pro-rata share of actual fuel and loss and unaccounted for gas on the transportation system. To the extent OG&E transports gas in quantities in excess of the prescribed MDQs or MHQs, it pays an overrun service charge. During the three months ended June 30, 2005 and 2004, OG&E paid Enogex approximately $11.9 million and $12.3 million, respectively, for gas transportation and storage services. During the six months ended June 30, 2005 and 2004, OG&E paid Enogex approximately $23.7 million and $24.1 million, respectively, for gas transportation and storage services.

Based upon requests for information from intervenors, OG&E requested from Enogex and Enogex retained a "cost of service" consultant to assist in the preparation of testimony related to this case. On March 31, 2004, OG&E filed testimony and exhibits with the OCC, which completed the initial documentation required to be filed in this case. On July 12, 2004, several parties filed responsive testimony reflecting various positions on the issues related to this case. In particular, the testimony of the OCC Staff recommended that OG&E be entitled to recover the $46.8 million annual demand fee requested, which results in no refund, and also recommended that OG&E provide at its next general rate review the results of an open competitive bidding process or a comprehensive market study. If OG&E does not provide such open bidding or market study, the OCC Staff recommendation would cap recovery at approximately $40 million at OG&E's next general rate review. The recommendations in the testimony of the Attorney General's office and the Oklahoma Industrial Energy Consumers would cap recovery at approximately $35 million and $31 million, respectively, with the difference between what OG&E has been collecting through its automatic fuel adjustment clause and these recommended amounts being refunded to customers.

Hearings in this case before an administrative law judge ("ALJ") occurred from September 16-22, 2004. On October 22, 2004, the ALJ overseeing the proceeding recommended approximately $41.9 million annual demand fee

recovery with OG&E refunding to its customers any demand fees collected in excess of this amount. The ALJ's recommendation also would have allowed OG&E to recover the amounts that Enogex charges OG&E (and that OG&E pays in kind) for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. OG&E and other parties to the proceeding appealed the ALJ's recommendation on November 1, 2004 and a hearing in this case was held before the OCC on December 7, 2004. On July 14, 2005, the OCC issued an order in this case that, with one exception, approved the recovery recommended by the ALJ. The one exception was that the OCC order disallowed the recovery by OG&E of the amount that Enogex charges OG&E for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. Over the last three years, this amount has ranged from $1.6 million to $3.7 million annually. OG&E currently expects this amount to be between approximately $1.2 million and $1.6 million in 2005. The OCC's order will require OG&E to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC's order. Based on the order, OG&E's refund obligation will be approximately $8.8 million at June 30, 2005, which the Company does not believe is material in light of previously established reserves. A filing will be made with the OCC to determine the exact amount of the refund. The OCC's order is subject to appeal by any party to the proceedings.

Pending Regulatory Matters

Currently, OG&E has one significant matter pending at the OCC which is a review of OG&E's recently filed application for a rate increase in Oklahoma. This matter, as well as several other matters pending before the OCC and the FERC, is discussed below.

OG&E Oklahoma Rate Case Filing

On May 20, 2005, OG&E filed with the OCC an application for an annual rate increase of approximately $89.1 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. The application also included, among other things, implementation of enhanced reliability programs in OG&E's system and increased fuel oil inventory, the establishment of a separate recovery mechanism for major storm expense, the establishment of new rate classes for public schools and related facilities, the establishment of a military base rider, the establishment of a new low income assistance tariff and the decision to make the guaranteed flat bill pilot tariff permanent for residential and small business customers. In the rate case filing, OG&E proposes that new rates go into effect upon issuance of an order by the OCC no later than 180 days from the date of filing of the application. The proposed effective date of the rate change is in January 2006. As provided in the Settlement Agreement, until OG&E seeks and obtains approval of a request to increase base rates to recover, among other things, the investment in the McClain Plant, OG&E will have the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the completion of the acquisition and the operation of the McClain Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. If the OCC were to approve OG&E's requested amount, all prudently incurred costs accrued through the regulatory asset within the 12-month period would be included in OG&E's prospective cost of service and would be recovered over a period to be determined by the OCC. OG&E's rate case application included approximately $25.9 million related to the McClain Plant regulatory asset. At June 30, 2005, the McClain Plant regulatory asset was approximately $24.5 million. OG&E completed its acquisition of the McClain Plant on July 9, 2004. Accordingly, OG&E ceased accruing various operating and related costs associated with the McClain Plant as a regulatory asset on July 8, 2005 and such costs will now be expensed in the Company's consolidated financial statements. OG&E estimates these amounts to be approximately $14.7 million for the six months ended December 31, 2005.

Competitive Bidding and Prudence Reviews for Electric Utility Providers

On March 10, 2005, the OCC filed Cause No. PUD 200500129 regarding "Inquiry of the Oklahoma Corporation Commission into Guidelines for Establishing Rules for Competitive Bidding and Prudence Reviews for Electric Utility Providers." As an electric utility provider, any such guidelines that were adopted would likely impact OG&E. Technical conferences were held in April 2005, and a hearing and deliberations were held in early June. On June 10, 2005, the OCC voted to close this notice of inquiry and directed the OCC Staff to open a rulemaking to address the competitive bidding issue for electric utilities. At this time, OG&E cannot determine the impact that this rulemaking could have on its operations.

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2003

On March 18, 2005, the OCC Staff filed Cause No. PUD 200500140 regarding "Application of the Public Utility Division Director for Public Hearing to Review and Monitor OG&E's Fuel Adjustment Clause for Calendar Year 2003." On June 10, 2005, the OCC voted to combine this case with OG&E's recently filed rate case discussed above.

Power Purchase Agreement Filings

On February 4, 2005, Chermac Energy Corporation ("Chermac") and Sleeping Bear, LLC filed an application at the OCC (Cause No. PUD 200500059) seeking establishment of purchased power rates and a power purchase agreement with OG&E pursuant to the Public Utility Regulatory Policy Act of 1978 ("PURPA") for Chermac's proposed Buffalo/Sleeping Bear wind project. On May 11, 2005, the OCC issued an order establishing a procedural schedule for this proceeding with hearings scheduled to begin on December 5, 2005. On May 27, 2005, OG&E filed a motion to dismiss this application. That motion is expected to be heard by an ALJ on or after August 15, 2005.

On April 28, 2005, Chermac and Sleeping Bear, LLC filed a second application at the OCC (Cause No. PUD 200500177) seeking establishment of purchased power rates and a power purchase agreement with OG&E pursuant to PURPA for Chermac's proposed Sleeping Bear South wind project. On June 10, 2005, the OCC issued an order establishing a procedural schedule for this proceeding with hearings scheduled to begin on January 23, 2006. On July 19, 2005, OG&E filed a motion to dismiss this application. That motion is expected to be heard by an ALJ on or after August 15, 2005.

OG&E Arkansas Rate Case Filing

OG&E is currently developing the information necessary to determine if a rate case filing in Arkansas is justified. OG&E expects to make a decision whether to file a rate case in Arkansas late in the third quarter of 2005.

Southwest Power Pool

The regional state committee, which is comprised of commissioners of the applicable state regulatory commissions, finished its process of formulating a methodology for funding transmission expansion in the Southwest Power Pool ("SPP") control area by allocating costs of transmission expansion to the SPP members who benefit. The SPP Board of Directors adopted this plan and filed it with the FERC on February 28, 2005, Docket No. ER05-652. The FERC conditionally accepted the plan on April 21, 2005 with an effective date of May 5, 2005. Also, the SPP is in the process of developing a process, required by the FERC, to create an imbalance energy market which will require cash settlements for over or under generation. Each SPP member will be responsible for monitoring its generation in its control area on an hourly basis and periodically submitting this information to the SPP, who will then provide settlement statements to each of the SPP members. The implementation date of the imbalance energy market requirements, which was initially planned to be effective October 1, 2005, has been suspended. The SPP Board of Directors voted on April 26, 2005 to make the implementation effective no later than March 1, 2006. On June 15, 2005, the SPP made a tariff filing in this matter. On July 26, 2005, the SPP Board of Directors voted to delay the implementation of the imbalance energy market requirements to May 1, 2006.

Market-Based Rate Authority

On December 22, 2003, OG&E and OERI filed a triennial market power update based on the supply margin assessment test. On April 14, 2004, the FERC issued: (1) interim requirements for the FERC jurisdictional electric utilities who have been granted authority to make wholesale sales at market-based rates; and (2) an order initiating a new rulemaking on future market-based rates authorizations. The interim method for analyzing generation market power requires two assessments – whether the utility is a pivotal supplier based on a control area's annual peak demand and whether the utility exceeds certain market share thresholds on a seasonal basis. If an applicant fails to pass either assessment, the FERC will presume that the utility can exercise generation market power and will initiate an investigation into the scope of the applicant's market power. The FERC will allow a utility to rebut that presumption through the submission of additional information. If an applicant is found to have generation market power, the applicant must propose a market power mitigation plan. The new interim assessment methods are applicable to all pending initial market-based rate applications and triennial reviews pending the rulemaking described below. On May 13, 2004, the FERC directed all utilities with pending three year market-based reviews to revise the generation market power portion of their three year review to address the two interim tests described above. In the rulemaking proceeding, the FERC is seeking comments on the adequacy of the FERC's current analysis of market-based rate filings, including the adequacy of the new "interim" assessment of generation market power. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 which shows the impact of the new requirements on OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but failed to pass the market share screen. OG&E and OERI provided an explanation as to why its failure of the market share screen should not be viewed as an indication that they can exercise generation market power. One party, Redbud, protested the OG&E and OERI filing and proposed that the FERC require OG&E to adopt an economic dispatch program as a means to mitigate OG&E's and OERI's generation market power. On March 15, 2005, OG&E and OERI responded to Redbud's protest. In that response OG&E and OERI reiterated that the information they initially filed demonstrates that they cannot

exercise market power and that Redbud's proposal is beyond the scope of the proceeding. Another party, AES, has requested intervention in this case in protest. In June 2005, the FERC granted the Redbud and AES interventions.

On June 7, 2005, the FERC issued an order on OG&E's and OERI's market-based rate filing. Because OG&E and OERI failed the market share screen for OG&E's control area, the FERC set OG&E's and OERI's market-based sales in OG&E's control area for investigation pursuant to Section 206 of the Federal Power Act to investigate whether OG&E and OERI may continue to sell power at market-based rates in OG&E's control area. The initiation of the investigation and imposition of the filing requirements do not constitute a finding that OG&E and OERI can exercise market power. OG&E and OERI have been requested to provide additional information that demonstrates to the FERC that they cannot exercise market power in the first-tier markets as well. However, the order conditionally allows OG&E and OERI to sell power in first-tier markets subject to OG&E and OERI providing additional information that clearly shows that they pass the market share screen for the first-tier markets. OG&E and OERI provided that additional information on July 7, 2005. By August 8, 2005, OG&E and OERI must either: (1) submit a delivered price test; (2) submit a mitigation proposal tailored to its specific circumstances that would eliminate the ability to exercise market power; or (3) inform the FERC that they will adopt the default cost-based rates described in the FERC's April 14, 2004 order in *AEP Power Marketing*. The FERC expects to conclude the investigation into OG&E's and OERI's market-based rates by October 31, 2005.

National Energy Legislation

In recent days, Congress passed a comprehensive energy bill, portions of which are of interest to the Company and to the industry. The bill has been sent to the President and is awaiting his signature before it becomes law. There are several provisions in the bill that may have a positive impact on the Company. Provisions minimizing the risk of future uneconomic purchased power contracts forced on the Company under PURPA, tax incentives for investment in electric transmission and gas pipeline systems, mandatory reliability requirements by the North American Electric Reliability Council with oversight by the FERC and improved FERC siting authority for construction of electric transmission in disputed areas are included in the bill. Another significant provision for the utility industry is the repeal of the Public Utility Holding Company Act of 1935. This provision appears to have little impact on the operations of the Company.

State Legislative Initiatives

Oklahoma

In the 2005 legislative session, House Bills 1910 and 1386 were introduced that may have an impact on the Company. House Bill 1910 which proposed that electric utilities: (i) be granted the certainty of knowing that costs of transmission upgrades assigned by a regional transmission organization will be recoverable, (ii) be granted the certainty of knowing that costs for a pre-approved plan to handle state and federally mandated environmental upgrades will be recoverable; and (iii) be able to seek pre-approval for generation construction projects, passed the legislature and was signed into law in May 11, 2005, at which time it became effective. House Bill 1386 proposed that utilities be able to continue to serve and expand, if so desired, in service territories in which they currently serve but which a municipality annexes. Currently, there is some legal uncertainty as to whether utilities can expand in an area described above. House Bill 1386 would have removed that uncertainty, but the bill failed to be heard for a final vote in the Senate so it will carry over in its current form in the next legislative session beginning February 2006.

Arkansas

In April 1999, Arkansas passed a law (the "Restructuring Law") calling for restructuring of the electric utility industry at the retail level. The Restructuring Law, which had initially targeted customer choice of electricity providers by January 1, 2002, was repealed in March 2003 before it was implemented. As part of the repeal legislation, electric public utilities were permitted to recover transition costs. OG&E incurred approximately $2.4 million in transition costs necessary to carry out its responsibilities associated with efforts to implement retail open access. On January 20, 2004, the APSC issued an order which authorized OG&E to recover approximately $1.9 million in transition costs over an 18-month period beginning February 2004. At June 30, 2005, OG&E has recovered approximately $1.8 million and expects to fully recover the remaining $0.1 million in July 2005.

13. Fair Value of Financial Instruments

The following information is provided regarding the estimated fair value of the Company's financial instruments, including derivative contracts related to the Company's price risk management activities, which have significantly changed since December 31, 2004.

	June 30, 2005		December 31, 2004	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 160.6**	**$ 160.6**	$ 130.3	$ 130.3
Interest Rate Swaps	**3.9**	**3.9**	7.9	7.9
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 134.3**	**$ 134.3**	$ 109.5	$ 109.5
Long-Term Debt				
Enogex Notes	**$ 474.1**	**$ 509.2**	$ 514.1	$ 556.3

The carrying value of the financial instruments on the Condensed Consolidated Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company's interest rate swaps and energy trading contracts was determined primarily based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties and the potential impact of liquidating the position in an orderly manner over a reasonable period of time. The fair value of the Company's long-term debt is based on quoted market prices and management's estimate of current rates available for similar issues with similar maturities.

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

Introduction

OGE Energy Corp. (collectively, with its subsidiaries, the "Company") is an energy and energy services provider offering physical delivery and management of both electricity and natural gas primarily in the south central United States. The Company conducts these activities through two business segments, the Electric Utility and the Natural Gas Pipeline segments.

The Electric Utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through Oklahoma Gas and Electric Company ("OG&E") and are subject to regulation by the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). OG&E was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries ("Enogex") and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. Enogex's focus is to utilize its gathering, processing, transportation and storage capacity to execute physical, financial and service transactions to capture margins across different commodities, locations or time periods. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership ("NOARK"), Enogex also owns a controlling interest in and operates Ozark Gas Transmission, L.L.C. ("OGT"), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri.

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in "Outlook", are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential", "project" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures; the Company's ability and the ability of its subsidiaries to obtain financing on favorable terms; prices of electricity, natural gas and natural gas liquids, each on a stand-alone basis and in relation to each other; business conditions in

the energy industry; competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company; unusual weather; federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company's market; environmental laws and regulations that may impact the Company's operations; changes in accounting standards, rules or guidelines; creditworthiness of suppliers, customers and other contractual parties; the higher degree of risk associated with the Company's nonregulated business compared with the Company's regulated utility business; and other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission including Exhibit 99.01 to the Company's Form 10-K for the year ended December 31, 2004.

Overview

Summary of Operating Results

Quarter ended June 30, 2005 as compared to quarter ended June 30, 2004

The Company reported net income of approximately $38.5 million, or $0.42 per diluted share, as compared to approximately $39.0 million, or $0.44 per diluted share, for the three months ended June 30, 2005 and 2004, respectively. The decrease in net income for the three months ended June 30, 2005 as compared to the same period in 2004 was primarily due to:

- OG&E reporting net income of approximately $29.7 million, or $0.33 per diluted share of the Company's common stock, as compared to approximately $30.4 million, or $0.34 per diluted share, for the three months ended June 30, 2005 and 2004, respectively; and
- Enogex's operations reporting net income of approximately $11.3 million, or $0.12 per diluted share of the Company's common stock, as compared to approximately $11.5 million, or $0.13 per diluted share, for the three months ended June 30, 2005 and 2004, respectively.

These decreases to net income as compared to the prior period were partially offset by:

- lower net interest expense of approximately $1.0 million at the holding company resulting in a net loss of approximately $0.03 per diluted share for each of the three month periods ended June 30, 2005 and 2004.

Six months ended June 30, 2005 as compared to six months ended June 30, 2004

The Company reported net income of approximately $43.8 million, or $0.48 per diluted share, as compared to approximately $49.2 million, or $0.56 per diluted share, for the six months ended June 30, 2005 and 2004, respectively. The decrease in net income for the six months ended June 30, 2005 as compared to the same period in 2004 was primarily due to:

- Enogex's operations, including discontinued operations, reporting net income of approximately $19.4 million, or $0.21 per diluted share of the Company's common stock, as compared to approximately $24.3 million, or $0.28 per diluted share, for the six months ended June 30, 2005 and 2004, respectively; and
- OG&E reporting net income of approximately $28.0 million, or $0.31 per diluted share of the Company's common stock, as compared to approximately $30.4 million, or $0.35 per diluted share, for the six months ended June 30, 2005 and 2004, respectively.

These decreases to net income as compared to the prior period were partially offset by:

- lower net interest expense of approximately $2.8 million at the holding company resulting in a net loss of approximately $0.04 per diluted share for the six months ended June 30, 2005 as compared to a net loss of approximately $0.07 per diluted share during the same period in 2004.

Earnings per share for the three and six months ended June 30, 2005 as compared to the same period in 2004 also were affected by a higher amount of common stock outstanding from the issuance of common stock in 2004 pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan ("DRIP/DSPP").

Regulatory Matters

As part of the settlement of OG&E's rate case in November 2002 (the "Settlement Agreement"), OG&E agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired generation

facilities pursuant to the terms set forth in the Settlement Agreement. Although the prescribed bidding process detailed in the Settlement Agreement provided that separate transportation services be bid for each generation facility, OG&E believed that, in order for it to achieve maximum coal generation, to deliver the lowest cost energy to its customers and to ensure reliable electric service, it must have integrated, firm no-notice load following service for both gas transportation and gas storage. Because the required integrated service was not available in the marketplace from parties other than Enogex, on April 29, 2003, OG&E filed an application with the OCC in which OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of OG&E's natural gas-fired generation facilities. OG&E will pay Enogex annual demand fees of approximately $46.8 million for the right to transport specified maximum daily quantities ("MDQ") and maximum hourly quantities ("MHQ") of gas at various minimum gas delivery pressures depending on the operational needs of the individual generating facility. In addition, OG&E supplies system fuel in-kind for its pro-rata share of actual fuel and loss and unaccounted for gas on the transportation system. To the extent OG&E transports gas in quantities in excess of the prescribed MDQs or MHQs, it pays an overrun service charge. During the three months ended June 30, 2005 and 2004, OG&E paid Enogex approximately $11.9 million and $12.3 million, respectively, for gas transportation and storage services. During the six months ended June 30, 2005 and 2004, OG&E paid Enogex approximately $23.7 million and $24.1 million, respectively, for gas transportation and storage services.

On July 14, 2005, the OCC issued an order in this case that, with one exception, approved the recovery recommended by the administrative law judge overseeing the proceeding. The one exception was that the OCC order disallowed the recovery by OG&E of the amount that Enogex charges OG&E for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. Over the last three years, this amount has ranged from $1.6 million to $3.7 million annually. OG&E currently expects this amount to be between approximately $1.2 million and $1.6 million in 2005. The OCC's order will require OG&E to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC's order. Based on the order, OG&E's refund obligation will be approximately $8.8 million at June 30, 2005, which the Company does not believe is material in light of previously established reserves. A filing will be made with the OCC to determine the exact amount of the refund. The OCC order is subject to appeal by any party to the proceedings, some of whom were recommending a recovery below $41.9 million annually. For further information, see Note 12 of Notes to Condensed Consolidated Financial Statements.

Coal Shipment Disruption

In July 2005, OG&E received notification from Union Pacific Railroad ("Union Pacific") that, in May 2005, Union Pacific and BNSF Railway ("BNSF") experienced successive derailments on the jointly-owned rail line serving the Southern Powder River Basin coal producers. According to Union Pacific, these two derailments were caused by track that had become unstable from an accumulation of coal dust in the roadbed combined with unusually heavy rainfall. BNSF, which maintains and operates the line, concluded that a significant part of the railroad must be repaired before normal train operations can resume. While the repairs are underway, Union Pacific will be unable to operate at full capacity from the Powder River Basin. Union Pacific estimates that it will only be able to supply between 80 and 85 percent of the current coal demand needs during the months of July to November until the line is restored to full capacity. As a result, OG&E's burnable coal inventory is projected to decline somewhat through November. However, OG&E's inventory strategy to carry a prudent quantity of inventory for just these situations is expected to permit OG&E to conduct normal operations through November without significant adjustments to its fuel mix assuming coal deliveries at the 80 to 85 percent level. OG&E has developed contingency plans to handle the situation in case inventory continues to decline beyond November.

Outlook

The Company's 2005 earnings guidance is between $149 million to $158 million of net income, or $1.65 to $1.75 per share, assuming approximately 91.0 million average diluted shares outstanding. See "Outlook" in the Company's Form 10-K for the year ended December 31, 2004 and in the Company's Form 10-Q for the quarter ended March 31, 2005 for a description of the underlying assumptions related to the earnings guidance for OG&E, Enogex and the holding company. The 2005 outlook includes earnings guidance of $106 million to $110 million, or $1.17 to $1.22 per share, at OG&E and $49 million to $56 million, or $0.54 to $0.62 per share, at Enogex, while earnings guidance at the holding company is a loss between $6 million and $8 million, or $0.07 to $0.09 per share. The earnings guidance recognizes that various operating and related expenses of the McClain Plant ceased being treated as a regulatory asset effective July 8, 2005 and will begin being expensed in the Company's consolidated financial statements.

Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets have not been determined nor included in the 2005 earnings guidance.

Results of Operations

The following discussion and analysis presents factors which affected the Company's consolidated results of operations for the three and six months ended June 30, 2005 as compared to the same period in 2004 and the Company's consolidated financial position at June 30, 2005. The following information should be read in conjunction with the Condensed Consolidated Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

	Three Months Ended June 30,		**Six Months Ended June 30,**	
(In millions, except per share data)	**2005**	2004	**2005**	2004
Operating income	**$ 81.4**	$ 82.5	**$ 107.4**	$ 113.5
Net income	**$ 38.5**	$ 39.0	**$ 43.8**	$ 49.2
Basic average common shares outstanding	**90.2**	87.6	**90.1**	87.6
Diluted average common shares outstanding	**90.8**	88.2	**90.6**	88.1
Basic earnings per average common share	**$ 0.43**	$ 0.44	**$ 0.49**	$ 0.56
Diluted earnings per average common share	**$ 0.42**	$ 0.44	**$ 0.48**	$ 0.56
Dividends declared per share	**$ 0.3325**	$ 0.3325	**$ 0.6650**	$ 0.6650

In reviewing its consolidated operating results, the Company believes that it is appropriate to focus on operating income as reported in its Condensed Consolidated Statements of Income as operating income indicates the ongoing profitability of the Company excluding unusual or infrequent items, the cost of capital and income taxes.

Operating Income (Loss) by Business Segment

	Three Months Ended June 30,		**Six Months Ended June 30,**	
(In millions)	**2005**	2004	**2005**	2004
OG&E (Electric Utility)	**$ 55.0**	$ 55.0	**$ 57.8**	$ 60.0
Enogex (Natural Gas Pipeline)	**26.6**	27.3	**48.8**	53.3
Other Operations (A)	**(0.2)**	0.2	**0.8**	0.2
Consolidated operating income	**$ 81.4**	$ 82.5	**$ 107.4**	$ 113.5

(A) Other Operations primarily includes unallocated corporate expenses and consolidating eliminations.

The following operating income analysis by business segment includes intercompany transactions that are eliminated in the Condensed Consolidated Financial Statements.

OG&E

	Three Months Ended June 30,		**Six Months Ended June 30,**	
(Dollars in millions)	**2005**	2004	**2005**	2004
Operating revenues	**$ 394.1**	$ 411.5	**$ 695.1**	$ 715.8
Cost of goods sold	**215.9**	242.9	**390.9**	426.1
Gross margin on revenues	**178.2**	168.6	**304.2**	289.7
Other operation and maintenance	**79.7**	71.5	**157.1**	143.0
Depreciation	**31.4**	30.3	**64.5**	62.2
Taxes other than income	**12.1**	11.8	**24.8**	24.5
Operating income	**$ 55.0**	$ 55.0	**$ 57.8**	$ 60.0
Operating revenues by classification				
Residential	**$ 150.0**	$ 151.6	**$ 264.2**	$ 276.6
Commercial	**101.4**	106.4	**171.6**	175.5

Industrial		**82.2**		88.7		**147.9**		153.6
Public authorities		**40.5**		42.2		**69.6**		71.1
Sales for resale		**13.7**		13.8		**26.8**		26.4
Provision for refund on gas transportation and storage case		**(1.1)**		---		**(2.1)**		(6.4)
Other		**6.5**		8.6		**15.8**		18.7
System sales revenues		**393.2**		411.3		**693.8**		715.5
Off-system sales revenues		**0.9**		0.2		**1.3**		0.3
Total operating revenues	**$**	**394.1**	$	411.5	**$**	**695.1**	$	715.8
MWH (A) sales by classification (in millions)								
Residential		**1.9**		1.8		**3.8**		3.7
Commercial		**1.5**		1.4		**2.8**		2.7
Industrial		**1.8**		1.7		**3.5**		3.4
Public authorities		**0.7**		0.7		**1.3**		1.3
Sales for resale		**0.4**		0.4		**0.7**		0.7
System sales		**6.3**		6.0		**12.1**		11.8
Off-system sales		**---**		---		**---**		---
Total sales		**6.3**		6.0		**12.1**		11.8
Number of customers		**739,983**		729,661		**739,983**		729,661
Average cost of energy per KWH (B) - cents								
Fuel		**2.864**		3.121		**2.644**		2.657
Fuel and purchased power		**3.216**		3.734		**3.023**		3.356
Degree days (C)								
Heating								
Actual		**202**		177		**1,867**		1,962
Normal		**236**		236		**2,199**		2,218
Cooling								
Actual		**644**		622		**645**		640
Normal		**547**		547		**555**		555

(A) Megawatt-hour
(B) Kilowatt-hour
(C) Degree days are calculated as follows: The high and low degrees of a particular day are added together and then averaged. If the calculated average is above 65 degrees, then the difference between the calculated average and 65 is expressed as cooling degree days, with each degree of difference equaling one cooling degree day. If the calculated average is below 65 degrees, then the difference between the calculated average and 65 is expressed as heating degree days, with each degree of difference equaling one heating degree day. The daily calculations are then totaled for the particular reporting period.

Quarter ended June 30, 2005 as compared to quarter ended June 30, 2004

OG&E’s operating income for the three months ended June 30, 2005 and 2004 remain unchanged at approximately $55.0 million. As described in more detail below, operating income was affected by higher gross margin on revenues (“gross margin”) offset by higher operation and maintenance expenses and higher depreciation expense.

Gross margin, which is operating revenues less cost of goods sold, was approximately $178.2 million for the three months ended June 30, 2005 as compared to approximately $168.6 million during the same period in 2004, an increase of approximately $9.6 million or 5.7 percent. The gross margin increased primarily due to:

- warmer weather in OG&E’s service territory which increased the gross margin by approximately $5.3 million;
- growth in OG&E’s service territory primarily due to customer growth and increased usage which increased the gross margin by approximately $3.7 million; and
- the seasonal over collection of revenues related to the cogeneration credit rider, implemented January 1, 2005, which increased the gross margin by approximately $1.9 million as the rider is based on an equal monthly amount of kwh usage as compared to actual kwh usage.

These increases in gross margin were partially offset by:

- the provision for refund associated with OG&E’s gas transportation and storage case which reduced the gross margin by approximately $1.1 million.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $171.6 million for the three months ended June 30, 2005 as compared to approximately $162.5 million during the same period in 2004, an increase of approximately $9.1 million or 5.6 percent. The increase was primarily due to increased generation partially offset by lower average cost of fuel per kwh. Purchased power costs were approximately

$44.3 million for the three months ended June 30, 2005 as compared to approximately $80.4 million during the same period in 2004, a decrease of approximately $36.1 million or 44.9 percent. The decrease was primarily due to OG&E's completion of the acquisition of a 77 percent interest in the 520 megawatt ("MW") NRG McClain Station (the "McClain Plant") in July 2004, the termination of a power purchase contract in August 2004 which was replaced with a new contract in September 2004 and the scheduled decrease in cogeneration capacity payments for another power purchase contract, which decreases became effective in January 2005.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through automatic fuel adjustment clauses. While the regulatory mechanisms for recovering fuel costs differ in Oklahoma, Arkansas and the FERC, in each jurisdiction the costs are passed through to customers and are intended to provide neither an ultimate benefit nor detriment to OG&E. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex. See Note 12 of Notes to Condensed Consolidated Financial Statements for a discussion of recently completed proceedings at the OCC regarding OG&E's gas transportation and storage contract with Enogex and a review of OG&E's automatic fuel adjustment clause for 2003.

Other operating and maintenance expenses were approximately $79.7 million for the three months ended June 30, 2005 as compared to approximately $71.5 million during the same period in 2004, an increase of approximately $8.2 million or 11.5 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries and wages expense of approximately $3.0 million, higher pension and benefit expense of approximately $1.2 million and higher employee expenses of approximately $0.4 million, primarily due to more capitalized costs during the second quarter of 2004 and increased salary and wage rates; and
- higher outside services expense of approximately $2.5 million and higher materials and supplies expense of approximately $0.5 million, primarily due to higher expenses for infrastructure projects in the second quarter of 2005 as spending on infrastructure projects in the second quarter of 2004 was postponed as OG&E awaited an OCC order regarding whether OG&E had to reduce its rates, effective January 1, 2004.

These increases in other operating and maintenance expenses were partially offset by:

- lower allocations from the holding company of approximately $0.6 million primarily due to lower miscellaneous corporate expenses.

Depreciation expense was approximately $31.4 million for the three months ended June 30, 2005 as compared to approximately $30.3 million during the same period in 2004, an increase of approximately $1.1 million or 3.6 percent, primarily due to a higher level of depreciable plant.

Six months ended June 30, 2005 as compared to six months ended June 30, 2004

OG&E's operating income for the six months ended June 30, 2005 decreased approximately $2.2 million or 3.7 percent as compared to the same period in 2004. As described in more detail below, the decrease in operating income was primarily attributable to higher operation and maintenance expenses and higher depreciation expense partially offset by higher gross margins.

Gross margin was approximately $304.2 million for the six months ended June 30, 2005 as compared to approximately $289.7 million during the same period in 2004, an increase of approximately $14.5 million or 5.0 percent. The gross margin increased primarily due to:

- growth in OG&E's service territory primarily due to customer growth and increased usage which increased the gross margin by approximately $8.8 million;
- the seasonal over collection of revenues related to the cogeneration credit rider, implemented January 1, 2005, which increased the gross margin by approximately $5.3 million as the rider is based on an equal monthly amount of kwh usage as compared to actual kwh usage; and
- warmer weather in OG&E's service territory which increased the gross margin by approximately $3.6 million.

These increases in gross margin were partially offset by:

- the provision for refund associated with OG&E's gas transportation and storage case which reduced the gross margin by approximately $2.1 million.

Fuel expense was approximately $303.9 million for the six months ended June 30, 2005 as compared to approximately $270.5 million during the same period in 2004, an increase of approximately $33.4 million or 12.3 percent. The increase was primarily due to increased generation partially offset by lower average cost of fuel per kwh. Purchased power costs were approximately $87.0 million for the six months ended June 30, 2005 as compared to approximately $155.6 million during the same period in 2004, a decrease of approximately $68.6 million or 44.1 percent. The decrease was primarily due to OG&E's completion of the acquisition of the McClain Plant in July 2004, the termination of a power purchase contract in August 2004 which was replaced with a new contract in September 2004 and the scheduled decrease in cogeneration capacity payments for another power purchase contract, which decreases became effective in January 2005.

Other operating and maintenance expenses were approximately $157.1 million for the six months ended June 30, 2005 as compared to approximately $143.0 million during the same period in 2004, an increase of approximately $14.1 million or 9.9 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries and wages expense of approximately $5.7 million, higher pension and benefit expense of approximately $1.6 million and higher employee expenses of approximately $1.0 million, primarily due to more capitalized costs during the first six months of 2004 and increased salary and wage rates; and

- o higher outside services expense of approximately $5.6 million and higher materials and supplies expense of approximately $2.5 million, primarily due to higher expenses for infrastructure projects in the first six months of 2005 as spending on infrastructure projects in the first six months of 2004 was postponed as OG&E awaited an OCC order regarding whether OG&E had to reduce its rates, effective January 1, 2004.

These increases in other operating and maintenance expenses were partially offset by:

- o lower allocations from the holding company of approximately $3.5 million primarily due to lower miscellaneous corporate expenses.

Depreciation expense was approximately $64.5 million for the six months ended June 30, 2005 as compared to approximately $62.2 million during the same period in 2004, an increase of approximately $2.3 million or 3.7 percent, primarily due to a higher level of depreciable plant.

The decreases in operating income for both the three and six month periods ended June 30, 2005 as compared to the same periods in 2004 is, in management's judgment, indicative of the need for an increase in OG&E's retail rates. See "OG&E Oklahoma Rate Case Filing" in Note 12 of Notes to Condensed Consolidated Financial Statements for a description of OG&E's recent filing with the OCC to increase its rates in Oklahoma by approximately $89.1 million annually. As indicated in Note 12, OG&E ceased accruing various operating and related costs associated with the McClain Plant as a

regulatory asset effective July 8, 2005 and will begin expensing these items, which is expected to adversely affect OG&E's operating results until recovery of such expenses is authorized by the OCC. OG&E estimates these amounts to be approximately $14.7 million for the six months ended December 31, 2005.

Enogex – Continuing Operations

	Three Months Ended June 30,		Six Months Ended June 30,	
(Dollars in millions)	**2005**	2004	**2005**	2004
Operating revenues	**$ 983.3**	$ 775.5	**$ 1,984.1**	$ 1,524.7
Cost of goods sold	**915.8**	707.3	**1,853.4**	1,390.8
Gross margin on revenues	**67.5**	68.2	**130.7**	133.9
Other operation and maintenance	**25.0**	25.1	**49.5**	48.4
Depreciation	**11.6**	11.4	**23.3**	22.9
Taxes other than income	**4.3**	4.4	**9.1**	9.3
Operating income	**$ 26.6**	$ 27.3	**$ 48.8**	$ 53.3
New well connects	**73**	57	**126**	120
Gathered volumes - TBtu/d (A)	**1.02**	0.99	**1.02**	1.00
Incremental transportation volumes - TBtu/d	**0.55**	0.53	**0.51**	0.47
Total throughput volumes - TBtu/d	**1.57**	1.52	**1.53**	1.47
Natural gas processed - Mmcf/d (B)	**562**	510	**531**	492
Natural gas liquids sold (keep-whole) - million gallons	**84**	50	**162**	103
Natural gas liquids sold (POL and fixed-fee) - million gallons	**3**	4	**7**	8
Total natural gas liquids sold - million gallons	**87**	54	**169**	111
Average sales price per gallon	**$ 0.750**	$ 0.680	**$ 0.748**	$ 0.669

(A) Trillion British thermal units per day.
(B) Million cubic feet per day.

Quarter ended June 30, 2005 as compared to quarter ended June 30, 2004

Enogex's operating income for the three months ended June 30, 2005 decreased approximately $0.7 million or 2.6 percent as compared to the same period in 2004. The decrease in operating income was primarily attributable to reductions in gross margins of approximately $3.8 million in Enogex's marketing business and approximately $3.7 million in Enogex's transportation and storage business, which were only partially offset by increased gross margins of approximately $6.8 million in Enogex's gathering and processing business.

Transportation and storage contributed approximately $29.7 million of Enogex's gross margin for the three months ended June 30, 2005 as compared to approximately $33.4 million during the same period in 2004, a decrease of approximately $3.7 million or 11.1 percent. The gross margin decreased primarily due to:

- o reduced fuel recoveries associated with under recovered fuel in prior periods which reduced the gross margin by approximately $4.2 million; and
- o a change in Enogex's accounting estimate of its natural gas storage inventory which reduced the gross margin by

approximately $3.4 million.

These decreases in the transportation and storage gross margin were partially offset by:

- o increased crosshaul prices and volumes which increased the gross margin by approximately $1.6 million; and
- o increased OGT natural gas sales margin primarily due to renegotiated contracts which increased the gross margin by approximately $1.6 million.

Gathering and processing contributed approximately $38.2 million of Enogex's gross margin for the three months ended June 30, 2005 as compared to approximately $31.4 million during the same period in 2004, an increase of approximately $6.8 million or 21.7 percent. Gathering gross margins increased approximately $1.4 million or 6.7 percent for the three months ended June 30, 2005 as compared to the same period in 2004. The gathering gross margin increased primarily due to:

- o contractual fuel gains primarily due to higher natural gas prices and renegotiated contracts which increased the gross margin by approximately $1.1 million; and
- o higher natural gas compression fees primarily due to an increase in low pressure gathering volumes (subject to compression fees) which increased the gross margin by approximately $0.7 million.

Processing gross margins increased approximately $5.4 million or 50.4 percent for the three months ended June 30, 2005 as compared to the same period in 2004 primarily due to:

- o increased keep-whole margins primarily due to higher commodity spreads which increased the gross margin by approximately $3.9 million; and
- o increased condensate margins primarily due to higher condensate prices which increased the gross margin by approximately $1.0 million.

Marketing reduced Enogex's gross margin by approximately $0.4 million for the three months ended June 30, 2005 as compared to a contribution of approximately $3.4 million during the same period in 2004, a decrease of approximately $3.8 million. The gross margin decreased primarily due to:

- o less favorable market conditions in the second quarter 2005 as compared to the same period in 2004 which reduced the gross margin by approximately $1.6 million;
- o losses in storage activity due to net temporary timing and gains from trading activities recorded in 2004 which reduced the gross margin by approximately $1.1 million; and
- o losses incurred related to Enogex's position on the Cheyenne Plains' transportation agreement which reduced the gross margin by approximately $0.8 million.

Enogex's other operating and maintenance expenses were approximately $25.0 million for the three months ended June 30, 2005 as compared to approximately $25.1 million during the same period in 2004, a decrease of approximately $0.1 million or 0.4 percent. The decrease in other operating and maintenance expenses was primarily due to:

- o lower allocations from the holding company of approximately $0.6 million due to lower miscellaneous corporate expenses.

This decrease in other operating and maintenance expenses was partially offset by:

- o expenses related to a pipeline rupture in the second quarter of 2005 of approximately $0.5 million.

During the three months ended June 30, 2004, Enogex had an increase in net income of approximately $2.6 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business. These increases in net income include:

- o authorized recovery of previously under recovered fuel of approximately $1.6 million; and
- o a gain on the sale of certain Enogex compression and processing assets of approximately $1.0 million.

Six months ended June 30, 2005 as compared to six months ended June 30, 2004

Enogex's operating income for the six months ended June 30, 2005 decreased approximately $4.5 million or 8.4 percent as compared to the same period in 2004. The decrease in operating income was primarily attributable to reductions in gross margins of approximately $8.2 million in Enogex's marketing business and approximately $4.2 million in Enogex's transportation and storage business and higher operating expenses, which were only partially offset by increased gross margins of approximately $9.2 million in Enogex's gathering and processing business.

Transportation and storage contributed approximately $59.7 million of Enogex's gross margin for the six months ended June 30, 2005 as compared to approximately $63.9 million during the same period in 2004, a decrease of approximately $4.2 million or 6.6 percent. The gross margin decreased primarily due to:

- o reduced fuel recoveries associated with under recovered fuel in prior periods which reduced the gross margin by approximately $7.5 million; and

- a change in Enogex's accounting estimate of its natural gas storage inventory which reduced the gross margin by approximately $3.4 million.

These decreases in the transportation and storage gross margin were partially offset by:

- increased OGT natural gas sales margin primarily due to renegotiated contracts which increased the gross margin by approximately $3.3 million; and
- increased crosshaul prices and volumes which increased the gross margin by approximately $2.8 million.

Gathering and processing contributed approximately $73.1 million of Enogex's gross margin for the six months ended June 30, 2005 as compared to approximately $63.9 million during the same period in 2004, an increase of approximately $9.2 million or 14.4 percent. Gathering gross margins increased approximately $1.9 million or 4.5 percent for the six months ended June 30, 2005 as compared to the same period in 2004. The gathering gross margin increased primarily due to:

- contractual fuel gains primarily due to higher natural gas prices and renegotiated contracts which increased the gross margin by approximately $2.3 million; and
- higher natural gas compression fees primarily due to an increase in low pressure gathering volumes (subject to compression fees) which increased the gross margin by approximately $1.2 million.

These increases in the gathering gross margin were partially offset by:

- lower margins on natural gas sales which reduced the gross margin by approximately $1.2 million.

Processing gross margins increased approximately $7.3 million or 34.1 percent for the six months ended June 30, 2005 as compared to the same period in 2004 primarily due to:

- increased keep-whole margins primarily due to higher commodity spreads which increased the gross margin by approximately $5.1 million; and
- increased condensate margins primarily due to higher condensate prices which increased the gross margin by approximately $2.3 million.

Marketing reduced Enogex's gross margin by approximately $2.1 million for the six months ended June 30, 2005 as compared to a contribution of approximately $6.1 million during the same period in 2004, a decrease of approximately $8.2 million. The gross margin decreased primarily due to:

- a correction to the accounting procedure for park and loan transactions (natural gas storage transactions) in 2004 which reduced the gross margin by approximately $7.7 million (see Note 10 of Notes to Condensed Consolidated Financial Statements); and
- losses incurred related to Enogex's position on the Cheyenne Plains' transportation agreement which reduced the gross margin by approximately $1.8 million.

These decreases in the marketing gross margin were partially offset by:

- lower demand fees paid for storage services due to establishing new rates for the new storage season which began April 1, 2004 which increased the gross margin by approximately $1.3 million; and
- gains in storage activity due to net temporary timing and gains from trading activities recorded in 2004 which increased the gross margin by approximately $1.3 million.

Enogex's other operating and maintenance expenses were approximately $49.5 million for the six months ended June 30, 2005 as compared to approximately $48.4 million during the same period in 2004, an increase of approximately $1.1 million or 2.3 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher outside services costs of approximately $1.1 million related to maintaining the integrity and safety of Enogex's pipeline and an inventory management study;
- higher materials and supplies expense of approximately $0.7 million due to the higher cost of consumables associated with pipeline maintenance activities; and
- expenses related to a pipeline rupture in the second quarter of 2005 of approximately $0.5 million.

These increases in other operating and maintenance expenses were partially offset by:

- lower allocations from the holding company of approximately $1.2 million due to lower miscellaneous corporate expenses.

During the six months ended June 30, 2005, Enogex had a decrease in net income of approximately $4.7 million relating to a correction to the accounting procedure for park and loan transactions in 2004. During the six months ended June 30, 2004, Enogex had an increase in net income of approximately $6.9 million, which the Company does not consider to be reflective of the ongoing profitability of Enogex's business. These increases in net income include:

- authorized recovery of previously under recovered fuel of approximately $2.8 million;
- an Oklahoma investment tax credit of approximately $2.0 million;
- a gain on the sale of certain Enogex compression and processing assets of approximately $1.7 million; and
- income from discontinued operations of approximately $0.4 million.

Consolidated Other Income and Other Expense, Net Interest Expense and Income Tax Expense

Other income includes, among other things, contract work performed by OG&E, non-operating rental income, gain on the sale of assets, minority interest income and miscellaneous non-operating income. Other income was approximately $0.9 million for the three months ended June 30, 2005 as compared to approximately $2.6 million during the same period in 2004, a decrease of approximately $1.7 million or 65.4 percent. The decrease in other income was primarily due to gains in the second quarter of 2004 of approximately $1.6 million on the sale of certain of Enogex's compression and processing assets and of approximately $0.3 million from the sale of land near the Company's principal executive offices.

Other income was approximately $2.6 million for the six months ended June 30, 2005 as compared to approximately $5.4 million during the same period in 2004, a decrease of approximately $2.8 million or 51.9 percent. The decrease in other income was primarily due to gains in the six months ended June 30, 2004 of approximately $2.8 million on the sale of certain of Enogex's compression and processing assets and of approximately $0.3 million from the sale of land near the Company's principal executive offices.

Other expense includes, among other things, expenses from the losses on the sale of assets, minority interest expense, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions. Other expense was approximately $1.0 million for the three months ended June 30, 2005 as compared to approximately $1.5 million during the same period in 2004, a decrease of approximately $0.5 million or 33.3 percent. The decrease in other expense was primarily due to a decrease in charitable donations in the second quarter of 2005 of approximately $0.3 million and a decrease in the liability associated with the deferred compensation plan and the restoration of retirement income plan of approximately $0.1 million.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $21.7 million for the three months ended June 30, 2005 as compared to approximately $23.5 million during the same period in 2004, a decrease of approximately $1.8 million or 7.7 percent. The decrease in net interest expense was primarily due to:

- a net reduction in interest expense of approximately $4.4 million due to the reduction of long-term debt outstanding; and
- a reduction in interest expense of approximately $0.5 million due to an increase in the allowance for borrowed funds used during construction.

These decreases in net interest expense were partially offset by:

- an increase in interest expense of approximately $2.1 million due to an increase in variable interest rates associated with the Company's interest rate swap agreements and variable rate industrial authority bonds; and
- an increase in interest expense of approximately $1.3 million due to higher commercial paper fees as a result of higher commercial paper outstanding.

Net interest expense was approximately $40.9 million for the six months ended June 30, 2005 as compared to approximately $46.6 million during the same period in 2004, a decrease of approximately $5.7 million or 12.2 percent. The decrease in net interest expense was primarily due to:

- a net reduction in interest expense of approximately $8.3 million due to the reduction of long-term debt outstanding;
- an increase in interest income of approximately $1.8 million due to the interest portion of an income tax refund related to prior periods; and
- a reduction in interest expense of approximately $1.0 million due to an increase in the allowance for borrowed funds used during construction.

These decreases in net interest expense were partially offset by:

- an increase in interest expense of approximately $3.9 million due to an increase in variable interest rates associated with the Company's interest rate swap agreements and variable rate industrial authority bonds; and
- an increase in interest expense of approximately $1.8 million due to higher commercial paper fees as a result of higher commercial paper outstanding.

Income tax expense for the three months ended June 30, 2005 and 2004 remain unchanged at approximately $21.1 million. Income tax expense was affected by:

- lower pre-tax income for the Company; and
- a reduction in certain permanent differences.

These items were offset by:

- o a decrease in Oklahoma state tax credits of approximately $0.7 million during the three months ended June 30, 2005 as compared to the same period in 2004.

Income tax expense was approximately $22.3 million for the six months ended June 30, 2005 as compared to approximately $20.5 million during the same period in 2004, an increase of approximately $1.8 million or 8.8 percent. The increase in income tax expense was primarily due to:

- o a decrease in Oklahoma state tax credits of approximately $4.4 million during the six months ended June 30, 2005 as compared to the same period in 2004.

This increase in income tax expense was partially offset by:

- o lower pre-tax income for the Company; and
- o a reduction in other permanent differences.

Financial Condition

The balance of Accounts Receivable was approximately $417.5 million and $487.9 million at June 30, 2005 and December 31, 2004, respectively, a decrease of approximately $70.4 million or 14.4 percent. The decrease was primarily due to a decrease in natural gas sales activity by Enogex in the second quarter of 2005 partially offset by an increase in OG&E's billings to its customers reflecting warmer weather in June 2005 as compared to December 2004.

The balance of Accrued Unbilled Revenues was approximately $78.2 million and $45.5 million at June 30, 2005 and December 31, 2004, respectively, an increase of approximately $32.7 million or 71.9 percent. The increase reflects higher seasonal electric rates and increased usage due to warmer weather during June 2005 as compared to December 2004.

The balance of Fuel Inventories was approximately $52.5 million and $89.0 million at June 30, 2005 and December 31, 2004, respectively, a decrease of approximately $36.5 million or 41.0 percent. The decrease was primarily due to inventory sales at Enogex during the first six months of 2005 and a decrease in OG&E's coal and natural gas inventories as a result of electric generation demand needs during the second quarter of 2005.

The balance of current Price Risk Management assets was approximately $135.4 million and $118.6 million at June 30, 2005 and December 31, 2004, respectively, an increase of approximately $16.8 million or 14.2 percent. The increase was primarily due to the natural timing of existing park and loan transactions (natural gas storage transactions) and related financial contracts associated with OGE Energy Resources, Inc.'s ("OERI") activities during the first six months of 2005.

The balance of the Gas Imbalance asset was approximately $129.2 million and $100.1 million at June 30, 2005 and December 31, 2004, respectively, an increase of approximately $29.1 million or 29.1 percent. The Gas Imbalance asset is comprised of planned or managed imbalances related to Enogex's marketing business, referred to as park and loan transactions, and pipeline and natural gas liquids imbalances, which are operational imbalances. Park and loan transactions were approximately $120.6 million and $76.0 million at June 30, 2005 and December 31, 2004, respectively, an increase of approximately $44.6 million or 58.7 percent. The increase resulted from economic opportunities in the marketplace.

The balance of Fuel Clause Under Recoveries was approximately $38.2 million and $54.3 million at June 30, 2005 and December 31, 2004, respectively, a decrease of approximately $16.1 million or 29.7 percent. The decrease in fuel clause under recoveries was due to the amount billed to OG&E's customers during the six months ended June 30, 2005 exceeding OG&E's cost of fuel. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel cost in periods of rising prices above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under or over recovery. OG&E expects to recover the fuel clause under recoveries during 2005.

The balance of Short-Term Debt was approximately $222.7 million and $125.0 million at June 30, 2005 and December 31, 2004, respectively, an increase of approximately $97.7 million or 78.2 percent. The increase was primarily due to the funding of bond interest, ad valorem taxes, dividends, pension plan liability and maturing long-term debt at Enogex and the daily operational needs of the Company.

The balance of Accounts Payable was approximately $388.5 million and $476.2 million at June 30, 2005 and December 31, 2004, respectively, a decrease of approximately $87.7 million or 18.4 percent. The decrease was primarily due to lower natural gas purchases in the first six months of 2005.

The balance of Accrued Taxes was approximately $27.2 million and $14.1 million at June 30, 2005 and December 31, 2004, respectively, an increase of approximately $13.1 million or 92.9 percent. The increase was primarily due to an increase in the Company's estimated income tax liability.

The balance of long-term Price Risk Management liabilities was approximately $25.0 million and $6.6 million at June 30, 2005 and December 31, 2004, respectively, an increase of approximately $18.4 million. The increase was primarily due to higher levels of activity associated with long-term physical gas transactions and related financial contracts associated with OERI's activities during the first six months of 2005.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements include any transactions, agreements or other contractual arrangements to which an unconsolidated entity is a party and under which the Company has: (i) any obligation under a guarantee contract having specific characteristics as defined in Financial Accounting Standards Board ("FASB") Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"; (ii) a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to such entity for such assets; (iii) any obligation, including a contingent obligation, under a contract that would be accounted for as a derivative instrument but is indexed to the Company's own stock and is classified in stockholders' equity in the Company's consolidated balance sheet; or (iv) any obligation, including a contingent obligation, arising out of a variable interest as defined in FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51," in an unconsolidated entity that is held by, and material to, the Company, where such entity provides financing, liquidity, market risk or credit risk support to, or engages in leasing, hedging or research and development services with, the Company. There have been no significant changes in the Company's off-balance sheet arrangements reported in the Company's Form 10-K for the year ended December 31, 2004 or the Company's Form 10-Q for the quarter ended March 31, 2005.

Liquidity and Capital Requirements

The Company's primary needs for capital are related to replacing or expanding existing facilities in OG&E's electric utility business and replacing or expanding existing facilities (including technology) at Enogex. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage and delays in recovering unconditional fuel purchase obligations. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings.

Interest Rate Swap Agreement

Fair Value Hedge

At June 30, 2005, OG&E had one outstanding interest rate swap agreement that qualified as a fair value hedge, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate ("LIBOR"). The objective of this interest rate swap was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. This interest rate swap qualified as a fair value hedge under Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

On April 1, 2005, Enogex terminated two interest rate swap agreements (with a total notional amount of $200 million) and received approximately $0.2 million related to this transaction. Since inception of the Enogex interest rate swap agreements, which converted $200 million of 8.125 percent fixed rate debt due January 15, 2010 to a floating rate based upon the three and six month LIBOR, the Company has paid approximately $81.3 million in interest and has received approximately $29.9 million related to these agreements. The effective interest rate until maturity will be approximately 7.67 percent on this long-term debt.

At June 30, 2005 and December 31, 2004, the fair value pursuant to OG&E's interest rate swap was approximately $3.9 million and the fair value hedge was classified as Deferred Charges and Other Assets – Price Risk Management in the Condensed Consolidated Balance Sheets. A corresponding net increase of approximately $3.9 million was reflected in Long-Term Debt at June 30, 2005 and December 31, 2004 as this fair value hedge was effective at June 30, 2005 and December 31, 2004.

Future Capital Requirements

Capital Expenditures

The Company's current 2005 to 2007 construction program includes continued investment in distribution, generation and transmission systems that is part of the Company's Customer Savings and Reliability Plan. OG&E has approximately 430 MWs of contracts with qualified cogeneration facilities and small power production producers' ("QF contracts") that will expire at the end of 2007, unless extended by OG&E. In addition, effective September 1, 2004, OG&E entered into a new 15-year power sales agreement for 120 MWs with PowerSmith Cogeneration Project, L.P. OG&E will continue reviewing all of the supply alternatives to these expiring QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates. Accordingly, OG&E will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, OG&E will also assess the feasibility of constructing additional base load coal-fired units. Approximately $7.0 million of the Company's capital expenditures budgeted for 2005 are to comply with environmental laws and regulations.

Debt Issuance

OG&E's 7.125 percent $110 million long-term debt series matures on October 15, 2005. OG&E currently expects to replace this maturing debt with new debt later this year.

Pension and Postretirement Benefit Plans

The Company plans to contribute approximately $32.0 million in 2005 to its pension plan, which represents the Company's 2004 pension expense. During the second quarter of 2005, the Company funded approximately $21.3 million to the pension plan. The remaining expected contributions to the pension plan in 2005, anticipated to be in the form of cash in the third quarter, are discretionary contributions and are not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

Future Sources of Financing

Management expects that internally generated funds, proceeds from the sales of common stock pursuant to the Company's DRIP/DSPP and long and short-term debt will be adequate over the next three years to meet anticipated capital

expenditures, operating needs, payment of dividends and maturities of long-term debt. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt

The following table shows the Company's lines of credit in place, commercial paper outstanding and available cash at June 30, 2005. At June 30, 2005, the Company's short-term borrowings consisted of borrowings on its revolving credit agreement and commercial paper.

Lines of Credit, Commercial Paper and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding	Maturity
OGE Energy Corp.	$ 15.0	$ ---	April 6, 2006 (A)
OG&E (B)	100.0	---	October 20, 2009 (C)
OGE Energy Corp. (D)	450.0	222.7	October 20, 2009 (C)
	565.0	222.7	
Cash	26.1	N/A	N/A
Total	$ 591.1	$ 222.7	

(A) In April 2005, the Company renewed its $15.0 million credit facility, shown in the table above, which matures April 6, 2006.
(B) No borrowings were outstanding at June 30, 2005 under this line of credit; however, $0.2 million of this line of credit supports a letter of credit.
(C) Each of the credit facilities has a five-year term with two options to extend the term for one year.
(D) This bank facility is available to back up a maximum of $300.0 million of the Company's commercial paper borrowings and can be used as a letter of credit facility. At June 30, 2005, the Company had approximately $85.0 million in outstanding borrowings under this line of credit and approximately $137.7 million in commercial paper borrowings.

The Company's and OG&E's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Their respective back-up lines of credit contain pricing grids based on our credit ratings that cause annual fees and borrowing rates to increase if they suffer an adverse ratings impact. The impact of any future downgrades would result in an increase in the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes.

Unlike the Company and Enogex, OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time for a two-year period beginning January 1, 2005 and ending December 31, 2006.

Railcar Lease Agreement

At December 31, 2004, OG&E has a noncancellable operating lease which has purchase options covering 1,464 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. At the end of the lease term which is March 31, 2006, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chose not to purchase the railcars and the actual value of the railcars was less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of approximately $36 million. OG&E is required to provide notice of its intentions related to the current railcar lease agreement by September 30, 2005. OG&E expects to enter into a new lease agreement for railcars effective April 1, 2006, which should negate any financial exposure under the current lease agreement.

Common Stock

The Company filed a registration statement to register 7,000,000 shares of its common stock for the Company's DRIP/DSPP in July 2005.

Critical Accounting Policies and Estimates

The Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements contain information that is pertinent to Management's Discussion and Analysis. In preparing the Condensed Consolidated

Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Condensed Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material affect on the Company's Condensed Consolidated Financial Statements particularly as they relate to pension expense and impairment estimates. However, the Company believes it has taken reasonable but conservative positions, where assumptions and estimates are used, in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, impairment estimates, contingency reserves, accrued removal obligations, regulatory assets and liabilities, unbilled revenue for OG&E, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and natural gas storage inventory and fair value and cash flow hedging policies. The selection, application and disclosure of these critical accounting estimates have been discussed with the Company's audit committee and are discussed in detail in Management's Discussion and Analysis of Financial Condition and Results of Operations in the Company's Form 10-K for the year ended December 31, 2004.

Accounting Pronouncements

See Note 2 of Notes to Condensed Consolidated Financial Statements for a discussion of a recent accounting pronouncement that is applicable to the Company.

Electric Competition; Regulation

OG&E and Enogex have been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although it appears unlikely in the near future that changes will occur to retail regulation in the states served by OG&E due to the significant problems faced by California in its electric deregulation efforts and other factors, significant changes are possible, which could significantly change the manner in which OG&E conducts its business. These developments at the federal and state levels are described in more detail in Notes 11 and 12 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q, in the Company's Form 10-K for the year ended December 31, 2004 and in the Company's Form 10-Q for the quarter ended March 31, 2005. OG&E currently has one important matter pending before the OCC. See Note 12 of Notes to Condensed Consolidated Financial Statements for a further discussion.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Except as disclosed otherwise in this Form 10-Q, in the Company's Form 10-K for the year ended December 31, 2004 and in the Company's Form 10-Q for the quarter ended March 31, 2005, management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. This assessment of currently pending or threatened lawsuits is subject to change. See Notes 11 and 12 of Notes to Condensed Consolidated Financial Statements and Item 1 of Part II in this Form 10-Q, Notes 17 and 18 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2004 and Notes 12 and 13 to the Company's Condensed Consolidated Financial Statements in the Company's Form 10-Q for the quarter ended March 31, 2005, for a discussion of the Company's commitments and contingencies.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Risk Management

The risk management process established by the Company is designed to measure both quantitative and qualitative risks in its businesses. A corporate risk management department, under the direction of a corporate risk oversight committee, has been established to review these risks on a regular basis. The Company is exposed to market risk in its normal course of business, including changes in certain commodity prices and interest rates. The Company also engages in price risk management activities for both trading and non-trading purposes.

To manage the volatility relating to these exposures, the Company enters into various derivative and other forward transactions pursuant to the Company's policies on hedging practices. These positions are monitored using techniques such as mark-to-market valuation, value-at-risk and sensitivity analysis.

Interest Rate Risk

The Company's exposure to changes in interest rates relates primarily to short-term debt, interest rate swap agreements and commercial paper. The Company manages its interest rate exposure by limiting its variable rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Except as set forth below, the Company's exposure to interest rate risk for changes in interest rates has not significantly changed since December 31, 2004. On April 1, 2005, Enogex terminated two interest rate swap agreements (with a total notional amount of $200 million) and received approximately $0.2 million related to this transaction. Since inception of the Enogex interest rate swap agreements, which converted $200 million of 8.125 percent fixed rate debt due January 15, 2010 to a floating rate based upon the three and six month LIBOR, the Company has paid approximately $81.3 million in interest and has received approximately $29.9 million related to these agreements. The effective interest rate until maturity will be approximately 7.67 percent on this long-term debt. See Notes 7 and 8 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q for a discussion of the Company's long-term and short-term debt activity.

Commodity Price Risk

The market risks inherent in the Company's market risk sensitive instruments, positions and anticipated commodity transactions are the potential losses in value arising from adverse changes in the commodity prices to which the Company is exposed. These market risks can be classified as trading, which includes transactions that are entered into voluntarily to capture subsequent changes in commodity prices, or non-trading, which includes the exposure some of the Company's assets have to commodity prices.

The trading activities are conducted throughout the year subject to daily and monthly trading stop loss limits of $2.5 million. The daily loss exposure from trading activities is measured primarily using value at risk, subject to a $1.5 million limit, as well as other quantitative risk measurement techniques. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company's operating income.

The prices of natural gas, natural gas liquids and natural gas liquids processing spreads are subject to fluctuations resulting from changes in supply and demand. The changes in these prices have a direct effect on the operating income received by the Company as compensation for operating some of its assets. To partially reduce non-trading commodity price risk incurred in the Company's normal course of business caused by these market fluctuations, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the operating income received by the Company as compensation for operating these assets. Because the commodities covered by these hedges are substantially the same commodities that the Company buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

Sensitivity analyses have been prepared to estimate the Company's exposure to the market risk of the Company's natural gas and natural gas liquids commodity positions. These analyses are done for both trading and non-trading activities. The Company's daily net commodity position consists of natural gas inventories, commodity purchase and sales contracts, financial and commodity derivative instruments and anticipated natural gas processing spreads and fuel recoveries. The value of trading positions is a summation of the fair values calculated for each commodity by valuing each net position at quoted market prices. Because quoted market prices are not available for all of the Company’s non-trading positions, the value of non-trading positions is a summation of the forecasted values calculated for each commodity based upon internally generated forecasted prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in such prices over the next 12 months. The results of these analyses, which may differ from actual results, are as follows as of June 30, 2005.

(In millions)	Trading	Non-Trading
Commodity market risk, net	$ 0.5	$ 7.6

Item 4. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company’s management, including the Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”), of the effectiveness of the Company’s disclosure controls and procedures, the CEO and CFO have concluded that the Company’s disclosure controls and procedures are effective.

In July 2005, Enogex completed the implementation of a new information system that, together with the Company’s primary enterprise-wide general ledger software, will be used to accumulate and analyze financial data used in financial reporting. Enogex will utilize this new system, along with other applications, to generate financial statements beginning with fiscal quarter ending September 30, 2005. The change in information systems was not made in response to any deficiency in Enogex’s internal controls. Except for the preceding change, which Enogex believes enhances their system of internal controls, there were no other changes during the Company’s most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934). As required by Sarbanes-Oxley, the controls and processes that are part of this new information system will be tested during the remainder of 2005 as part of the Company’s Sarbanes-Oxley Section 404 compliance requirements.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

Reference is made to Part I, Item 3 of the Company’s Form 10-K for the year ended December 31, 2004 and Part II, Item 1 of the Company’s Form 10-Q for the quarter ended March 31, 2005 for a description of certain legal proceedings presently pending. Except as set forth below and in Notes 11 and 12 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q, there are no new significant cases to report against the Company or its subsidiaries and there have been no material changes in the previously reported proceedings.

1. As reported in Part I, Item 3 (Legal Proceedings) of the Company’s Form 10-K for the year ended December 31, 2004 and in Note 12 to the Company’s Form 10-Q for the quarter ended March 31, 2005, the Company has been involved in legal proceedings filed by Jack J. Grynberg in federal courts related to natural gas measurement. A ruling in this case by the special master was received in May 2005 which dismissed OG&E and all Enogex parties named in these proceedings. This ruling may be appealed.

2. OG&E has been sued by Kaiser-Francis Oil Company in District Court, Blaine County, Oklahoma. This case has been pending for more than 10 years. Plaintiff alleges that OG&E breached the terms of numerous contracts covering approximately 60 wells by failing to purchase gas from Plaintiff in amounts set forth in the contracts. Plaintiff seeks $25.0 million in take-or-pay damages and $1.8 million in underpayment damages. Over the objection and unsuccessful appeal by OG&E, Plaintiff has been permitted to amend its petition to include a claim based on theories of tort. Specifically, Plaintiff alleges, among other things, that OG&E intentionally and tortuously interfered with contracts by falsifying documents, sponsoring false testimony and putting forward legal defenses, which are known by OG&E to be without merit. If successful, Plaintiff believes that these theories could give Plaintiff a basis to seek punitive damages. This lawsuit was stayed pending the outcome of an appeal that OG&E filed in a similar case brought by Kaiser-Francis in Grady County.

In the Grady case, the plaintiff alleged that OG&E breached the terms of several gas purchase contracts in amounts set forth in the contracts. In 2001, the district court rendered a verdict against OG&E in the amount of approximately $8.0 million, including pre-judgment interest and attorneys’ fees. OG&E filed an appeal and on May 18, 2004, the Court of Appeals issued an opinion reversing the judgment and remanding for a new trial. The appellate court found that the trial court committed reversible error in rejecting a portion of OG&E’s interpretation of the commercial well provisions of the gas purchase contracts, and in failing to recognize issues of fact for the jury relating to OG&E’s contention regarding the correct initial reserve estimate on one of the natural gas wells, the Thiel No 1-9. In addition, the appellate court made rulings favorable to OG&E relating to the statutory measure of damages, the effect of line pressure adjustment provisions in the contracts, and the admission of certain hearsay evidence. The appellate court made rulings favorable to Kaiser-Francis relating to the effect of royalty payment obligations on the amount of damages, the effect of the amount of reserves owned by Kaiser-Francis in the wells on OG&E’s gas purchase obligation, the propriety of the award of prejudgment interest, and OG&E’s liability for the payment of gross production taxes pertaining to the damages awarded. The appellate court returned

an issue relating to the alleged effect of Kaiser-Francis’s failure to make gas available for consideration by the trial court. Finally, the appellate court denied Kaiser-Francis’s request for appeal-related attorney’s fees and costs. On July 6, 2004, the Court of Appeals denied Kaiser-Francis’s motion for rehearing. Both parties filed petitions for certiorari with the Oklahoma Supreme Court for the review of those portions of the appellate court’s opinion unfavorable to each. The Oklahoma Supreme Court denied both parties’ petitions for certiorari on January 10, 2005. Mandate was issued by the Oklahoma Supreme Court on February 4, 2005. Since then, the Blaine County case has been set for trial beginning January 17, 2006. The Grady County case has been set for trial beginning October 17,

2005. Additionally, Kaiser-Francis has filed a motion in the Grady County case asking for permission to amend its petition to include a claim based on the same theories of tort as alleged in the Blaine County case. On May 19, 2005, the trial court denied Kaiser-Francis' request to amend its petition to add tort claims.

OG&E believes that, to the extent Plaintiff were successful on the merits of its claims of OG&E's failure to take gas in either the Blaine County case or Grady County case, these amounts would be recoverable through its regulated electric rates. The claims related to tortuous conduct, which OG&E believes at this time are without merit, would not appear to be recoverable in its electric rates.

3. On July 22, 2005, Enogex Inc., Enogex Products Corporation and Enogex Gas Gathering, L.L.C. were served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs' own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including the Enogex companies, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs' wells. The plaintiffs' assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages in excess of $10,000, plus attorneys' fees and costs, and punitive damages in excess of $10,000. Based on its investigation to date, the Company believes this lawsuit is without merit and intends to vigorously defend this case.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

The shares indicated below represent shares of Company common stock purchased on the open market by the trustee for the Company's Stock Ownership and Retirement Savings Plan and reflect shares purchased with employee contributions as well as the portion attributable to the Company's matching contributions.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
1/1/05 - 1/31/05	77,500	$25.84	N/A	N/A
2/1/05 - 2/28/05	65,000	$25.90	N/A	N/A
3/1/05 - 3/31/05	26,100	$26.69	N/A	N/A
4/1/05 - 4/30/05	73,800	$26.96	N/A	N/A
5/1/05 - 5/31/05	17,800	$27.77	N/A	N/A
6/1/05 - 6/30/05	38,600	$28.35	N/A	N/A

N/A - not applicable

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

(a) The Company's Annual Meeting of Shareowners was held on May 19, 2005.

(b) Not applicable.

(c) The matters voted upon and the results of the voting at the Annual Meeting were as follows:

(1) The Shareowners voted to elect the Company's nominees for election to the Board of Directors as follows:

Herbert H. Champlin – 80,057,745 votes for election and 1,312,296 votes withheld

Linda P. Lambert – 80,094,334 votes for election and 1,275,707 votes withheld

Ronald H. White – 80,115,764 votes for election and 1,254,277 votes withheld

(2) The Shareowners voted to ratify the appointment of Ernst & Young LLP as the Company's principal independent accountants for 2005 with 79,978,492 votes for election, 819,386 votes against and 572,158 votes abstained.

Item 6. Exhibits.

Exhibit No.	Description
31.01	Certifications Pursuant to Rule 13a-14(a)/15d-14(a) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURE

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

OGE ENERGY CORP.
(Registrant)

By /s/ Donald R. Rowlett

Donald R. Rowlett
Vice President and Controller

(On behalf of the registrant and in his capacity as Chief Accounting Officer)

August 3, 2005

Exhibit 31.01

CERTIFICATIONS

I, Steven E. Moore, certify that:

1. I have reviewed this quarterly report on Form 10-Q of OGE Energy Corp.;

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

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

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

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

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

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

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

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

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

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

Date: August 3, 2005

/s/ Steven E. Moore

Steven E. Moore
Chairman of the Board, President and
Chief Executive Officer

Exhibit 31.01

CERTIFICATIONS

I, James R. Hatfield, certify that:

1. I have reviewed this quarterly report on Form 10-Q of OGE Energy Corp.;

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

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

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

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

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

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

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

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

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

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

Date: August 3, 2005

/s/ James R. Hatfield

James R. Hatfield
Senior Vice President and
Chief Financial Officer

Exhibit 32.01

Certification Pursuant to 18 U.S.C. Section 1350
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report of OGE Energy Corp. (the "Company") on Form 10-Q for the period ended June 30, 2005, as filed with the Securities and Exchange Commission (the "Report"), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

August 3, 2005

/s/ Steven E. Moore

Steven E. Moore
Chairman of the Board, President
and Chief Executive Officer

/s/ James R. Hatfield

James R. Hatfield

Senior Vice President and
Chief Financial Officer