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 March 31, 2007

OR

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

Commission File Number: 1-12579

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 o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated Filer x Accelerated Filer o Non-Accelerated Filer o

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

At March 31, 2007, 91,744,897 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED MARCH 31, 2007

TABLE OF CONTENTS

	Page
FORWARD-LOOKING INFORMATION	1
Part I – FINANCIAL INFORMATION	
Item 1. Financial Statements (Unaudited)	
Condensed Consolidated Statements of Income	2
Condensed Consolidated Balance Sheets	3
Condensed Consolidated Statements of Cash Flows	5
Notes to Condensed Consolidated Financial Statements	6
Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations	24
Item 3. Quantitative and Qualitative Disclosures About Market Risk	36
Item 4. Controls and Procedures	37
Part II – OTHER INFORMATION	
Item 1. Legal Proceedings	37
Item 1A. Risk Factors	38
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds	38
Item 6. Exhibits	38
Signature	39

FORWARD-LOOKING STATEMENTS

Except for the historical statements contained herein, certain of the matters discussed in this Form 10-Q, including those matters discussed in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations," 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. In addition to the specific risk factors discussed in "Item 1A. Risk Factors" and "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations," factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures;
- OGE Energy Corp.'s (collectively, with its subsidiaries, the "Company") ability and the ability of its subsidiaries to obtain financing on favorable terms;
- prices and availability of electricity, coal, 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;
- availability and prices of raw materials for current and future construction projects;
- federal or state legislation and regulatory decisions (including the approval of future regulatory filings with the Oklahoma Corporation Commission ("OCC") or the Arkansas Public Service Commission ("APSC") related to its proposed construction of a new power plant and the outcome of Oklahoma Gas and Electric Company's ("OG&E") current Federal Energy Regulatory Commission ("FERC") audit) 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 markets;
- environmental laws and regulations that may impact the Company's operations;
- changes in accounting standards, rules or guidelines;
- the discontinuance of regulated accounting principles under Financial Accounting Standards Board Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation";
- 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 Risk Factors and Exhibit 99.01 to the Company's Form 10-K for the year ended December 31, 2006.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

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

	Three Months Ended March 31,	
(In millions, except per share data)	**2007**	2006
OPERATING REVENUES		
Electric Utility operating revenues	**$ 340.7**	$ 374.0
Natural Gas Pipeline operating revenues	**540.8**	735.8
Total operating revenues	**881.5**	1,109.8
COST OF GOODS SOLD (exclusive of depreciation shown below)		
Electric Utility cost of goods sold	**188.2**	225.9
Natural Gas Pipeline cost of goods sold	**478.7**	662.6
Total cost of goods sold	**666.9**	888.5
Gross margin on revenues	**214.6**	221.3
Other operation and maintenance	**98.8**	105.5
Depreciation	**48.7**	44.9
Taxes other than income	**20.9**	19.1
OPERATING INCOME	**46.2**	51.8
OTHER INCOME (EXPENSE)		
Interest income	**0.7**	1.5
Other income	**2.6**	6.6
Other expense	**(0.9)**	(1.1)
Net other income	**2.4**	7.0
INTEREST EXPENSE		
Interest on long-term debt	**22.1**	21.7
Allowance for borrowed funds used during construction	**(0.6)**	(1.0)
Interest on short-term debt and other interest charges	**2.7**	2.0
Interest expense	**24.2**	22.7
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**24.4**	36.1
INCOME TAX EXPENSE	**7.2**	12.0
INCOME FROM CONTINUING OPERATIONS	**17.2**	24.1
DISCONTINUED OPERATIONS (NOTE 5)		
Income from discontinued operations	---	1.3
Income tax expense	---	0.5
Income from discontinued operations	---	0.8
NET INCOME	**$ 17.2**	$ 24.9
BASIC AVERAGE COMMON SHARES OUTSTANDING	**91.5**	90.6
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**92.4**	91.6
BASIC EARNINGS PER AVERAGE COMMON SHARE		
Income from continuing operations	**$ 0.19**	$ 0.26
Income from discontinued operations, net of tax	---	0.01
NET INCOME	**$ 0.19**	$ 0.27
DILUTED EARNINGS PER AVERAGE COMMON SHARE		
Income from continuing operations	**$ 0.19**	$ 0.26
Income from discontinued operations, net of tax	---	0.01
NET INCOME	**$ 0.19**	$ 0.27
DIVIDENDS DECLARED PER SHARE	**$ 0.34**	$ 0.3325

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

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	**March 31, 2007**	December 31, 2006
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 32.4**	$ 47.9
Funds on deposit	**32.0**	32.0
Accounts receivable, less reserve of $3.7 and $4.4, respectively	**303.3**	344.3
Accrued unbilled revenues	**34.2**	39.7
Fuel inventories	**57.3**	65.6
Materials and supplies, at average cost	**62.9**	58.7
Price risk management	**7.9**	41.9
Gas imbalances	**3.6**	2.8
Accumulated deferred tax assets	**13.7**	10.6
Prepayments	**8.6**	9.0
Other	**9.4**	11.6
Total current assets	**565.3**	664.1
OTHER PROPERTY AND INVESTMENTS, at cost	**37.5**	35.2
PROPERTY, PLANT AND EQUIPMENT		
In service	**6,496.3**	6,307.7
Construction work in progress	**100.3**	191.1
Total property, plant and equipment	**6,596.6**	6,498.8
Less accumulated depreciation	**2,648.6**	2,631.3
Net property, plant and equipment	**3,948.0**	3,867.5
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**16.8**	31.1
Regulatory asset - SFAS 158	**225.5**	231.1
Price risk management	**1.5**	1.7
McClain Plant deferred expenses	**17.1**	18.7
Unamortized loss on reacquired debt	**19.8**	20.1
Unamortized debt issuance costs	**9.2**	9.4
Other	**20.6**	23.1
Total deferred charges and other assets	**310.5**	335.2
TOTAL ASSETS	**$ 4,861.3**	$ 4,902.0

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

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

(In millions)	**March 31, 2007**	December 31, 2006
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	**$ 303.9**	$ 295.0
Dividends payable	**31.2**	31.1
Customer deposits	**55.2**	53.4
Accrued taxes	**26.8**	57.0
Accrued interest	**30.0**	37.7
Accrued compensation	**26.7**	46.0
Long-term debt due within one year	**3.0**	3.0
Price risk management	**6.5**	9.2
Gas imbalances	**13.1**	11.1
Fuel clause over recoveries	**126.3**	96.3
Other	**28.6**	33.2
Total current liabilities	**651.3**	673.0
LONG-TERM DEBT	**1,346.1**	1,346.3
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**234.1**	231.3
Accumulated deferred income taxes	**847.8**	859.2
Accumulated deferred investment tax credits	**25.6**	26.8
Accrued removal obligations, net	**132.4**	125.5
Price risk management	**0.9**	1.1
Other	**32.4**	35.0
Total deferred credits and other liabilities	**1,273.2**	1,278.9
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**750.5**	741.0
Retained earnings	**873.0**	890.8
Accumulated other comprehensive loss, net of tax	**(32.8)**	(28.0)
Total stockholders' equity	**1,590.7**	1,603.8
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 4,861.3**	$ 4,902.0

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

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

(In millions)	Three Months Ended March 31, **2007**	2006
CASH FLOWS FROM OPERATING ACTIVITIES		
Income from continuing operations	**$ 17.2**	$ 24.1
Adjustments to reconcile income from continuing operations to net cash provided from operating activities		
Depreciation	**48.7**	44.9
Deferred income taxes and investment tax credits, net	**4.1**	4.5
Gain on sale of assets	---	(0.6)
Stock-based compensation expense	**1.0**	1.1
Price risk management assets	**34.2**	73.1
Price risk management liabilities	**(8.3)**	(67.4)
Other assets	**5.7**	7.7
Other liabilities	**(5.2)**	0.8
Change in certain current assets and liabilities		
Accounts receivable, net	**41.0**	256.3
Accrued unbilled revenues	**5.5**	1.5
Fuel, materials and supplies inventories	**4.1**	(4.5)
Gas imbalance asset	**(0.8)**	21.1
Fuel clause under recoveries	---	57.1
Other current assets	**2.6**	9.8
Accounts payable	**8.9**	(215.1)
Customer deposits	**1.8**	1.1
Accrued taxes	**(28.6)**	(41.4)
Accrued interest	**(14.0)**	(8.2)
Accrued compensation	**(19.3)**	(12.2)
Gas imbalance liability	**2.0**	(12.1)
Fuel clause over recoveries	**30.0**	---
Other current liabilities	**(4.6)**	(5.3)
Net Cash Provided from Operating Activities	**126.0**	136.3
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures (less allowance for equity funds used during construction)	**(119.6)**	(84.5)
Proceeds from sale of assets	**0.5**	0.9
Net Cash Used in Investing Activities	**(119.1)**	(83.6)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from long-term debt	---	217.5
Decrease in short-term debt, net	---	(250.0)
Issuance of common stock	**7.0**	1.9
Contributions from partners	**1.7**	---
Dividends paid on common stock	**(31.1)**	(30.1)
Net Cash Used in Financing Activities	**(22.4)**	(60.7)
DISCONTINUED OPERATIONS		
Net cash provided from operating activities	---	1.1
Net cash used in investing activities	---	(0.2)
Net Cash Provided from Discontinued Operations	---	0.9
NET DECREASE IN CASH AND CASH EQUIVALENTS	**(15.5)**	(7.1)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**47.9**	26.4
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 32.4**	$ 19.3

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

1. Summary of Significant Accounting Policies

Organization

The Company is an energy and energy services provider offering physical delivery and related services for 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 OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E 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. In May 2006, Enogex Gas Gathering, L.L.C. ("Gathering"), a wholly-owned subsidiary of Enogex Inc., sold certain gas gathering assets in the Kinta, Oklahoma, area, which have been reported as discontinued operations in the Company's Condensed Consolidated Financial Statements (see Note 5 for a further discussion).

The Company allocates operating costs to its subsidiaries based on several factors. Operating costs directly related to specific subsidiaries are assigned to those subsidiaries. Where more than one subsidiary benefits from certain expenditures, the costs are shared between those subsidiaries receiving the benefits. Operating costs incurred for the benefit of all subsidiaries are allocated among the subsidiaries, 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, net operating revenues and gross property, plant and equipment. The Company adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. 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 March 31, 2007 and December 31, 2006, the results of its operations for the three months ended March 31, 2007 and 2006, and the results of its cash flows for the three months ended March 31, 2007 and 2006, have been included and are of a normal recurring nature.

Due to seasonal fluctuations and other factors, the operating results for the three months ended March 31, 2007 are not necessarily indicative of the results that may be expected for the year ending December 31, 2007 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, 2006.

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 SFAS No. 71. 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.

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)		**March 31, 2007**		December 31, 2006
Regulatory Assets				
Regulatory asset - SFAS 158	**$**	**225.5**	$	231.1
Unamortized loss on reacquired debt		**19.8**		20.1
McClain Plant deferred expenses		**17.1**		18.7
Income taxes recoverable from customers, net		**16.8**		31.1
Pension plan expenses		**13.6**		14.7
Cogeneration credit rider under recovery		**0.1**		3.1
Miscellaneous		**0.3**		0.4
Total Regulatory Assets	**$**	**293.2**	$	319.2
Regulatory Liabilities				
Accrued removal obligations, net	**$**	**132.4**	$	125.5
Fuel clause over recoveries		**126.3**		96.3
Deferred gain on sale of assets		**2.4**		2.7
Miscellaneous		**0.3**		---
Total Regulatory Liabilities	**$**	**261.4**	$	224.5

The Company adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R," effective December 31, 2006, which required the Company to separately disclose the items that have not yet been recognized as components of net periodic pension cost, including net loss, prior service cost and net transition obligation at December 31, 2006. For companies not subject to SFAS No. 71, SFAS No. 158 required this information to be included in Accumulated Other Comprehensive Income. However, for companies subject to SFAS No. 71, this information is allowed to be recorded as a regulatory asset if: (i) the utility has historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates; and (ii) there is no negative evidence that the existing regulatory treatment will change. Therefore, OG&E has recorded the net loss, prior service cost and net transition obligation as a regulatory asset as these expenses are probable of future recovery. If, in the future, the regulatory bodies indicated a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the SFAS No. 158 regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

The changes in the SFAS No. 158 regulatory asset for the three months ended March 31, 2007 are as follows:

(In millions)		
Regulatory asset – SFAS 158:		
Defined benefit pension plan:		
Net loss	**$**	**(2.1)**
Prior service cost		**(1.1)**
Defined benefit postretirement plans:		
Net loss		**(1.4)**
Net transition obligation		**(0.6)**
Prior service cost		**(0.4)**
Total	**$**	**(5.6)**

The components of the SFAS No. 158 regulatory asset are as follows:

(In millions)	**March 31, 2007**	December 31, 2006
Defined benefit pension plan:		
Net loss	**$ 127.8**	$ 129.9
Prior service cost	**20.8**	21.9
Defined benefit postretirement plans:		
Net loss	**58.9**	60.3
Net transition obligation	**14.6**	15.2
Prior service cost	**3.4**	3.8
Total Regulatory Asset – SFAS 158	**$ 225.5**	$ 231.1

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.

Reclassifications

Certain prior year amounts have been reclassified on the Condensed Consolidated Financial Statements to conform to the 2007 presentation.

2. Accounting Pronouncement

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115," which permits all entities to choose, at specified election dates, to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The decision about whether to elect the fair value option is applied instrument by instrument, is irrevocable unless a new election date occurs and is applied only to an entire instrument and not to only specified risks, specific cash flows or portions of that instrument. A business entity must report unrealized gains and losses on items for which the fair value option has been elected in earnings (or another performance indicator if the business entity does not report earnings) at each subsequent reporting date. Upfront costs and fees related to items for which the fair value option is elected must be recognized in earnings as incurred and not deferred. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of a fiscal year that begins on or before November 15, 2007, provided the entity also elects to apply the provisions of SFAS No. 157, "Fair Value Measurements." The Company will adopt this new standard effective January 1, 2008. Management has not yet determined what the impact of this new standard will be on its consolidated financial position or results of operations.

3. Stock-Based Compensation

On January 21, 1998, the Company adopted a Stock Incentive Plan (the "1998 Plan"). In 2003, the Company adopted, and its shareowners approved, a new Stock Incentive Plan (the "2003 Plan" and together with the 1998 Plan, the "Plans"). The 2003 Plan replaced the 1998 Plan and no further awards will be granted under the 1998 Plan. As under the 1998 Plan, under the 2003 Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees of the Company and its subsidiaries. The Company has authorized the issuance of up to 2,700,000 shares under the 2003 Plan.

Effective January 1, 2006, the Company adopted SFAS No. 123(R), "Share-Based Payment," using the modified prospective transition method. Under that transition method, compensation cost recognized in the first quarter of 2006 included: (i) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the fair value calculated in accordance with the provisions of SFAS No. 123(R); and (ii) compensation cost for all share-based payments granted in the first quarter of 2006 based on the fair value calculated in accordance with the provisions of SFAS No. 123(R).

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded compensation expense of approximately $1.8 million pre-tax ($1.1 million after tax, or $0.01 per basic and diluted share) during the three months ended March 31, 2006 related to the Company's share-based payments. Also, as a result of adopting SFAS No. 123(R), the Company recorded a cumulative effect adjustment of approximately $0.4 million pre-tax ($0.2 million after tax, or less than $0.01 per basic and diluted share) on January 1, 2006 for outstanding non-vested share-based compensation grants at December 31, 2005. The Company determined that the cumulative effect adjustment was immaterial for presentation purposes and is, therefore, included in Other Operation and Maintenance Expense in the Condensed Consolidated Statement of Income. The Company recorded compensation expense of approximately $0.8 million pre-tax ($0.5 million after tax, or $0.01 per basic and diluted share) during the three months ended March 31, 2007 related to the Company's share-based payments.

During the three months ended March 31, 2007, the Company awarded 122,044 performance units based on total shareholder return and 40,686 performance units based on earnings per share with a grant date fair value of $24.18 and $33.59, respectively, to certain employees of the Company and its subsidiaries. Also, during the three months ended March 31, 2007, the Company converted 132,845 performance units based on a payout ratio of 169.25 percent of the target number of performance units granted in February 2004. Of the performance units converted, two-thirds were settled in the Company's common stock (149,891 shares) and one-third was paid in cash. Also, in January 2007, all of the Company's outstanding stock options became fully vested.

The Company issues new shares to satisfy stock option exercises. During the three months ended March 31, 2007, there were 286,339 shares of new common stock issued pursuant to the Company's Stock Incentive Plan related to exercised stock options. The Company received approximately $7.0 million and $1.9 million during the three months ended March 31, 2007 and 2006, respectively, related to exercised stock options.

4. Accumulated Other Comprehensive Loss

The components of total comprehensive income for the three months ended March 31, 2007 and 2006, respectively, are as follows:

	Three Months Ended March 31,	
(In millions)	**2007**	2006
Net income	**$ 17.2**	$ 24.9
Other comprehensive income (loss), net of tax:		
Defined benefit pension plan:		
Net loss, net of tax	**(0.3)**	---
Prior service cost, net of tax	**(0.2)**	---
Defined benefit postretirement plans:		
Net loss, net of tax	**(0.1)**	---
Net transition obligation, net of tax	**(0.1)**	---
Deferred hedging gains (losses), net of tax	**5.5**	(0.5)
Total comprehensive income	**$ 22.0**	$ 24.4

The components of accumulated other comprehensive loss at March 31, 2007 and December 31, 2006 are as follows:

(In millions)	**March 31, 2007**	December 31, 2006
Defined benefit pension plan:		
Net loss, net of tax ($34.4 and $34.9 pre-tax, respectively)	**$ (21.1)**	$ (21.4)
Prior service cost, net of tax ($5.3 and $5.6 pre-tax, respectively)	**(3.2)**	(3.4)
Defined benefit postretirement plans:		
Net loss, net of tax ($11.5 and $11.7 pre-tax, respectively)	**(5.3)**	(5.4)
Net transition obligation, net of tax ($1.1 and $1.2 pre-tax, respectively)	**(0.7)**	(0.8)
Prior service cost, net of tax ($1.1 and $1.1 pre-tax, respectively)	**(0.7)**	(0.7)
Deferred hedging gains, net of tax ($0.1 and $9.1 pre-tax, respectively)	**0.1**	5.6
Settlement and amortization of cash flow hedge, net of tax ($3.1 and $3.1 pre-tax, respectively)	**(1.9)**	(1.9)
Total accumulated other comprehensive loss	**$ (32.8)**	$ (28.0)

5. Enogex – Discontinued Operations

In March 2006, Enogex announced that its wholly-owned subsidiary, Gathering, had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction were approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and Enogex recorded an after tax gain of approximately $34.1 million during the second quarter of 2006. The proceeds from the sale, were used, among other things, to reduce short-term debt levels and fund capital expenditures.

The Condensed Consolidated Financial Statements of the Company have been reclassified to reflect Gathering's sale of certain gas gathering assets in Kinta, Oklahoma, which was part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of the Gathering assets that were sold have been excluded from the respective captions in the Condensed Consolidated Financial Statements and have been separately reported as discontinued operations in the applicable financial statement captions. Summarized financial information for the discontinued operations as of March 31 is as follows:

CONDENSED CONSOLIDATED STATEMENTS OF INCOME DATA

	Three Months Ended March 31,	
(In millions)	**2007**	2006
Operating revenues from discontinued operations	**$ ---**	$ 6.6
Income from discontinued operations before taxes	**$ ---**	$ 1.3

6. Income Taxes

The Company files consolidated income tax returns in the U.S. federal jurisdiction and various state jurisdictions. 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. The Company continues to amortize its federal investment tax credits on a ratable basis throughout the year. This ratable amortization results in a larger percentage reconciling item related to these credits during the first quarter when the Company historically experiences decreased book income. The following schedule reconciles the statutory federal tax rate to the effective income tax rate:

	Three Months Ended March 31,	
	2007	2006
Statutory federal tax rate	**35.0%**	35.0%
State income taxes, net of federal income tax benefit	**2.2**	3.8
Amortization of net unfunded deferred taxes	**0.9**	0.2
Federal investment tax credits, net	**(4.9)**	(3.3)
Federal renewable energy credit	**(2.7)**	---
401(k) dividends	**(0.7)**	(2.2)
Medicare Part D subsidy	**(0.6)**	(0.2)
Other	**0.3**	(0.1)
Effective income tax rate as reported	**29.5%**	33.2%

In connection with the filing in the third quarter of 2003 of the Company's consolidated income tax returns for 2002, OG&E elected to change its tax method of accounting related to the capitalization of costs for self-constructed assets to another method prescribed in the Income Tax regulations. The accounting method change was for income tax purposes only. For financial accounting purposes, the only change was recognition of the impact of the cash flow generated by accelerating income tax deductions. This was reflected in the financial statements as a switch from current income taxes payable to deferred income taxes payable. This tax accounting method change resulted in a one-time catch-up deduction for costs previously capitalized under the prior method, resulting in a consolidated tax net operating loss for 2002. This tax net operating loss eliminated the Company's current federal and state income tax liability for 2002 and 2003 and all estimated payments made for 2002 were refunded. The Company received federal and state income tax refunds of approximately $50.8 million during 2003 related to this tax accounting method change.

With few exceptions, the Company is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years before 2001. During 2005, new guidelines were issued by the Internal Revenue Service ("IRS") related to the change in the method of accounting used to capitalize costs for self-construction discussed above. The Company's current IRS examination process for the years 2002 and 2003, which was completed in the second quarter of 2006, identified this change in method of accounting as an issue under examination. As a result of their examination, the IRS disagreed with the change OG&E made in 2002 and determined that OG&E should change its tax method of accounting for the capitalization of costs for self-constructed assets to another method prescribed in the Income Tax regulations. The Company filed a formal protest with the IRS on July 21, 2006 (related to the 2002 and 2003 examination) requesting a hearing with the IRS to review the IRS's determination that the tax accounting method OG&E elected in 2002 was not appropriate. On August 17, 2006, the Company made a deposit with the IRS in anticipation that a portion of prior year deductions will be disallowed. During the first quarter of 2007, the IRS concluded its examination of the 2004 tax year and proposed significant adjustments related to the same method of accounting issue as the previous two years. The Company continues to disagree with the adjustments and filed a separate protest on April 2, 2007 related to the 2004 tax year. The impact of this matter on future cash flows is uncertain but could be material. The Company cannot predict either the final outcome or the timing of the resolution of this matter.

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an amendment of FASB Statement No. 109," on January 1, 2007. As a result of the implementation of FIN No. 48, the Company recognized approximately a $3.8 million increase in the accrued interest liability, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings. The balance of uncertain tax positions at January 1, 2007 consisted of approximately $171.6 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility (see discussion of the tax method of accounting for the capitalization of costs for self-constructed assets above). Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The Company recognizes accrued interest related to unrecognized tax benefits in interest expense and recognizes penalties in operating and maintenance expense. During the three months ended March 31, 2007 and 2006, respectively, OG&E recorded approximately $0.7 million and $0.8 million in interest. At March 31, 2007 and December 31, 2006, respectively, the Company had approximately $10.5 million and $3.5 million of accrued interest, an increase of approximately $7.0 million. This increase was primarily due to an additional interest accrual of approximately $6.3 million as required upon adoption of FIN No. 48 related to the tax method of accounting for the capitalization of costs for self-constructed assets.

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.

7. Earnings Per Share

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

	Three Months Ended March 31,	
(In millions)	**2007**	2006
Average Common Shares Outstanding		
Basic average common shares outstanding	**91.5**	90.6
Effect of dilutive securities:		
Employee stock options and unvested stock grants	**0.3**	0.2
Contingently issuable shares (performance units)	**0.6**	0.8
Diluted average common shares outstanding	**92.4**	91.6

For the three months ended March 31, 2007, all shares related to outstanding employee stock options were included in the calculation of diluted earnings per average common share as the exercise price of the stock options was lower than the average common stock market price during the period. For the three months ended March 31, 2006, there were approximately 0.3 million shares related to outstanding employee stock options, which 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 period.

8. Long-Term Debt

At March 31, 2007, the Company is in compliance with all of its debt agreements.

Long-Term Debt with Optional Redemption Provisions

OG&E's $125.0 million principal amount 6.65 percent Senior Notes ("Senior Notes") due July 15, 2027, are repayable on July 15, 2007, at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to July 15, 2007. Only holders who submit requests for repayment between May 15, 2007 and June 15, 2007 are entitled to such repayments. In accordance with SFAS No. 6, "Classification of Short-Term Obligations Expected to Be Refinanced," the Senior Notes are classified as long-term debt at March 31, 2007 due to OG&E having sufficient long-term liquidity in place as a result of increasing its revolving credit agreement to $400.0 million in December 2006. Also, based on the recent trading prices of the Senior Notes, OG&E does not believe it is probable that this option will be exercised by the note holders.

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 (dollars in millions):

SERIES	DATE DUE	AMOUNT
3.57% - 3.73%	Garfield Industrial Authority, January 1, 2025	**$ 47.0**
3.50% - 3.78%	Muskogee Industrial Authority, January 1, 2025	**32.4**
3.46% - 3.72%	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 believes that it has sufficient long-term liquidity to meet these obligations.

9. Short-Term Debt

There was no short-term debt outstanding at March 31, 2007 or December 31, 2006. The following table shows the Company's revolving credit agreements and available cash at March 31, 2007.

Revolving Credit Agreements and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding	Weighted-Average Interest Rate	Maturity
OGE Energy Corp. (A)	$ 600.0	$ ---	---	December 6, 2011 (C)
OG&E (B)	400.0	---	---	December 6, 2011 (C)
	1,000.0	---	---	
Cash	32.4	N/A	N/A	N/A
Total	$ 1,032.4	$ ---	---	

(A) This bank facility is available to back up the Company's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At March 31, 2007, there were no outstanding commercial paper borrowings.
(B) This bank facility is available to back up OG&E's commercial paper borrowings and to provide revolving credit borrowings. At March 31, 2007, OG&E had outstanding approximately $3.1 million supporting letters of credit and no commercial paper borrowings.
(C) In December 2006, the Company and OG&E amended and restated their revolving credit agreements to total in the aggregate $1.0 billion, $600 million for the Company and $400 million for OG&E. Each of the credit facilities has a five-year term with an option to extend the term for two additional one-year periods. Also, each of these credit facilities has an additional option at the end of the two renewal options to convert the outstanding balance to a one-year term loan.

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. Pricing grids associated with the back-up lines of credit could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. 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 $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2007 and ending December 31, 2008.

10. Retirement Plans and Postretirement Benefit Plans

In September 2006, the FASB issued SFAS No. 158 which requires an employer to: (i) recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity; and (ii) measure the fair value of the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. The requirement to initially recognize the funded status of the defined benefit postretirement plan and the disclosure requirements were effective for the year ended December 31, 2006 for the Company. The requirement to measure plan assets and benefit obligations at fair value in accordance with SFAS No. 157 as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. SFAS No. 158 also requires additional disclosures for defined benefit pension plans and other defined benefit postretirement plans.

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 March 31,	
(In millions)	**2007**	2006
Service cost	**$ 5.3**	$ 5.1
Interest cost	**8.1**	7.8
Return on plan assets	**(11.0)**	(9.6)
Amortization of net loss	**2.7**	4.2
Amortization of recognized prior service cost	**1.4**	1.5
Net periodic benefit cost (A)	**$ 6.5**	$ 9.0

	Postretirement Benefit Plans	
	Three Months Ended March 31,	
(In millions)	**2007**	2006
Service cost	**$ 1.0**	$ 0.9
Interest cost	**3.1**	3.0
Return on plan assets	**(1.5)**	(1.4)
Amortization of transition obligation	**0.7**	0.7
Amortization of net loss	**1.5**	2.2
Amortization of recognized prior service cost	**0.5**	0.5
Net periodic benefit cost	**$ 5.3**	$ 5.9

(A) In addition to the $6.5 million in SFAS No. 87, "Employers' Accounting for Pensions," net periodic benefit cost recognized during the three months ended March 31, 2007, OG&E also recognized an expense of approximately $1.1 million related to the reversal of a portion of the regulatory asset identified as Pension Plan Expenses in Note 1.

Pension Plan Funding

The Company previously disclosed in its Form 10-K for the year ended December 31, 2006 that it may contribute up to $50 million to its pension plan during 2007. In April 2007, the Company contributed approximately $20 million to its pension plan and currently expects to contribute an additional $30 million to its pension plan during the remainder of 2007. Any expected contributions to the pension plan during 2007 are discretionary contributions, anticipated to be in the form of cash, and are not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

11. 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 months ended March 31, 2007 and 2006 primarily included unallocated corporate expenses, interest expense on commercial paper, interest expense on long-term debt and consolidating eliminations. 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 months ended March 31, 2007 and 2006.

Three Months Ended March 31, 2007	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 340.7**	**$ 557.8**	**$ ---**	**$ (17.0)**	**$ 881.5**
Cost of goods sold	**199.9**	**484.0**	**---**	**(17.0)**	**666.9**
Gross margin on revenues	**140.8**	**73.8**	**---**	**---**	**214.6**
Other operation and maintenance	**74.2**	**27.8**	**(3.2)**	**---**	**98.8**
Depreciation	**35.4**	**11.3**	**2.0**	**---**	**48.7**
Taxes other than income	**15.2**	**4.5**	**1.2**	**---**	**20.9**
Operating income	**16.0**	**30.2**	**---**	**---**	**46.2**
Interest income	**---**	**2.6**	**1.6**	**(3.5)**	**0.7**
Other income	**1.3**	**0.3**	**1.0**	**---**	**2.6**
Other expense	**0.6**	**0.1**	**0.2**	**---**	**0.9**
Interest expense	**15.6**	**8.1**	**4.0**	**(3.5)**	**24.2**
Income tax expense (benefit)	**(0.8)**	**9.4**	**(1.4)**	**---**	**7.2**
Net income (loss)	**$ 1.9**	**$ 15.5**	**$ (0.2)**	**$ ---**	**$ 17.2**
Total assets	**$ 3,612.9**	**$ 1,306.8**	**$ 1,970.1**	**$ (2,028.5)**	**$ 4,861.3**

(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 March 31, 2007	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	**$ 59.1**	**$ 165.6**	**$ 461.4**	**$ (128.3)**	**$ 557.8**
Operating income	**$ 11.8**	**$ 18.1**	**$ 0.3**	**$ ---**	**$ 30.2**

Three Months Ended March 31, 2006		Electric Utility		Natural Gas Pipeline (A)		Other Operations		Intersegment		Total
(In millions)										
Operating revenues	$	374.0	$	763.2	$	---	$	(27.4)	$	1,109.8
Cost of goods sold		237.7		678.0		---		(27.2)		888.5
Gross margin on revenues		136.3		85.2		---		(0.2)		221.3
Other operation and maintenance		79.7		28.6		(2.8)		---		105.5
Depreciation		33.1		10.2		1.6		---		44.9
Taxes other than income		13.7		4.3		1.1		---		19.1
Operating income		9.8		42.1		0.1		(0.2)		51.8
Interest income		1.0		2.5		1.4		(3.4)		1.5
Other income		0.1		6.0		0.5		---		6.6
Other expense		1.0		---		0.1		---		1.1
Interest expense		13.7		8.1		4.3		(3.4)		22.7
Income tax expense (benefit)		(2.7)		16.3		(1.5)		(0.1)		12.0
Income (loss) from continuing operations	$	(1.1)	$	26.2	$	(0.9)	$	(0.1)	$	24.1
Income from discontinued operations	$	---	$	0.8	$	---	$	---	$	0.8
Net income (loss)	$	(1.1)	$	27.0	$	(0.9)	$	(0.1)	$	24.9
Total assets	$	3,202.3	$	1,423.7	$	1,849.6	$	(1,958.7)	$	4,516.9

(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 March 31, 2006		Transportation and Storage		Gathering and Processing		Marketing		Eliminations		Total
(In millions)										
Operating revenues	$	64.6	$	159.9	$	677.1	$	(138.4)	$	763.2
Operating income	$	22.1	$	16.4	$	3.6	$	---	$	42.1

12. Commitments and Contingencies

Except as set forth below and in Note 13, the circumstances set forth in 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, 2006 appropriately represent, in all material respects, the current status of the Company's material commitments and contingent liabilities.

Capital Expenditures

The Company's current 2007 to 2012 construction program includes continued investment in OG&E's distribution, generation and transmission system and Enogex's pipeline assets. The Company's current estimates of capital expenditures for 2007 through 2012 are approximately $570.9 million, $753.5 million, $689.7 million, $563.7 million, $529.6 million and $492.1 million, respectively, which include capital expenditures of approximately $92.7 million, $278.8 million, $285.7 million, $97.7 million and $34.1 million, respectively, in 2007 through 2011 related to the construction of the Red Rock power plant as discussed in Note 13.

Agreement with Cheyenne Plains Gas Pipeline Company, L.L.C.

Cheyenne Plains Gas Pipeline Company, L.L.C ("Cheyenne Plains") operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas with a capacity of 730,000 decatherms/day ("Dth/day"). OGE Energy Resources, Inc. ("OERI"), a wholly-owned subsidiary of the Company, entered into a Firm Transportation Service Agreement ("FTSA") with Cheyenne Plains in 2004, for 60,000 Dth/day of firm capacity on the Cheyenne Plains Pipeline. The FTSA was for a 10-year term beginning with the in-service date of the Cheyenne Plains Pipeline in March 2005 with an annual demand fee of approximately $7.4 million. Effective March 1, 2007, OERI and Cheyenne Plains amended the FTSA to provide for OERI to turn back 20,000 Dth/day of its capacity beginning in January 2008 for the remainder of the term. OERI's new demand fee obligations, net of this turn back and other immaterial release agreements, are estimated at approximately $6.9 million in 2007; $5.9 million in 2008; $6.5 million for each of the years 2009 through 2014; and $1.6 million in 2015.

Agreement with Midcontinent Express Pipeline, LLC

On December 15, 2006, Enogex announced that it had entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC for a primary term of 10 years (subject to possible extensions) for certain capacity on the Enogex system. The leased capacity provided for in this agreement is up to 0.5 billion cubic feet ("Bcf") per day and is dependent on the shipper volumes that commit to the project. Enogex's capacity will be a part of the proposed Midcontinent Express Pipeline ("MEP"), a joint venture between Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. In addition to the Enogex leased capacity, the proposed MEP project includes a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Pending necessary regulatory approval, the MEP project is currently expected to be in service by February 2009. Depending on the final capacity that MEP subscribes to pursuant to the agreement, Enogex expects its revenues from this firm capacity lease agreement to be between $12 million and $30 million annually. The Company currently estimates that its capital expenditures related to this project during the next two to three years could be between $65 million and $100 million. Enogex's lease agreement with MEP is subject to certain contingencies including regulatory approval. Prior to such approval, Enogex may incur expenditures of between approximately $20 million and $40 million with the majority being for certain commitments for materials that can be sold or used in normal operations in the event the MEP project does not proceed and the amount not recovered or utilized for such expenditures is not expected to be material.

Agreement with Boardwalk's Gulf Crossing Project

In March 2007, Enogex entered into a firm capacity lease agreement with Gulf Crossing Pipeline Company LLC for a primary term of seven years (subject to a possible extension) for certain capacity on the Enogex system. The leased capacity provided for in this agreement is up to 0.165 Bcf per day and is dependent on the shipper volumes that commit to the project. Boardwalk Pipeline Partners, LP, has announced plans to build the Gulf Crossing pipeline, which includes 355 miles of new interstate natural gas pipeline. It initially is expected to transport gas from the supply areas in Sherman, Texas, Bennington, Oklahoma, and Paris, Texas to the Perryville, Louisiana Hub. Depending on the final capacity that Gulf Crossing subscribes to pursuant to the agreement, Enogex expects its revenues from this firm capacity lease agreement to be between $1.6 million and $5.7 million annually. Enogex currently estimates that its capital expenditures related to this project during the next two to three years could be approximately $5 million. The lease agreement with Gulf Crossing is subject to certain regulatory approval. Prior to such approval, Enogex may incur expenditures of approximately $5 million with the majority being for certain commitments for material that can be sold or used in normal operations in the event the Gulf Crossing project does not proceed and the amount not recovered or utilized for such expenditures is not expected to be material. Subject to regulatory approvals, the Gulf Crossing project is expected to be in service during the fourth quarter of 2008.

Natural Gas

OG&E completed a request for proposal ("RFP") in February 2007 for approximately 63 percent of its projected natural gas requirements for the period April 2007 through October 2007. Additional gas supplies to fulfill OG&E's remaining natural gas requirements will be acquired through an additional RFP in the summer, along with monthly and daily purchases, all of which are considered competitive purchases.

Purchased Power

On November 1, 2006, OG&E issued an RFP for energy purchases for the summer of 2007 and signed a purchase contract for these purchases in April. Because it is for a period of less than one year, the contract is not subject to the OCC's

2006 competitive procurement rules. In March 2007, OG&E issued an RFP for capacity and/or firm energy purchases for the summer periods of 2008 through 2010. Completion of the process is expected in mid-summer 2007 and is subject to review by the OCC.

Natural Gas Measurement Case

United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E. (United States District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al. (United States District Court for the Eastern District of Louisiana, Case No. 97-2089; United States District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with Plaintiff's complaint, which is a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleges: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and British thermal unit content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees.

In qui tam actions, the United States Government can intervene and take over such actions from the relator. The Department of Justice, on behalf of the United States Government, decided not to intervene in this action.

The plaintiff filed over 70 other cases naming over 300 other defendants in various Federal Courts across the country containing nearly identical allegations. The Multidistrict Litigation Panel entered its order in late 1999 transferring and consolidating for pretrial purposes approximately 76 other similar actions filed in nine other Federal Courts. The consolidated cases are now before the United States District Court for the District of Wyoming.

In October 2002, the court granted the Department of Justice's motion to dismiss certain of the plaintiff's claims and issued an order dismissing the plaintiff's valuation claims against all defendants. Various procedural motions have been filed. A hearing on the defendants' motions to dismiss for lack of subject matter jurisdiction, including public disclosure, original source and voluntary disclosure requirements was held in 2005 and the special master ruled that OG&E and all Enogex parties named in these proceedings should be dismissed. This ruling was appealed to the District Court of Wyoming.

On October 20, 2006, the District Court of Wyoming ruled on Grynberg's appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex Services Corp., Transok, Inc. and OG&E, for lack of subject matter jurisdiction. Judgment was entered on November 17, 2006 and Grynberg filed his notice of appeal with the District Court of Wyoming. The defendants filed motions for attorneys' fees regarding issues of liability and Rule 11 motions on January 8, 2007. The defendants also filed for other legal costs on December 18, 2006. A hearing on these motions was held on April 24, 2007, at which time the judge in this matter took these motions under advisement. Grynberg has also filed appeals with the Tenth Circuit Court of Appeals. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Calpine Corporation Bankruptcy

Calpine Corporation, Calpine Energy Services, L.P., and several other affiliates (collectively "Calpine") voluntarily filed for Chapter 11 bankruptcy protection from creditors on December 20, 2005 (Case No. 05-60200 (BRL)) in the United States Bankruptcy Court, S.D. of New York. Enogex provides natural gas transportation services to two Calpine-owned power generation plants in Oklahoma pursuant to long-term contracts. Calpine is continuing to operate the plants and request services pursuant to the contracts. The total unpaid amount due to Enogex from Calpine is approximately $0.3 million which has been fully reserved on the Company's books. Negotiations continue as the parties are discussing potential amendments to the contracts that service the two Calpine plants as part of the bankruptcy restructuring plan.

A Calpine-owned power generation plant in Oklahoma is contractually obligated to provide capacity and energy to OG&E. The Calpine plant also pays, through the Southwest Power Pool ("SPP"), for transmission services provided to OG&E. OG&E expects both arrangements to remain in effect; however, whether Calpine in its bankruptcy proceedings will ultimately reject these agreements with OG&E is unknown.

Environmental Laws and Regulations

OG&E

Air

On June 15, 2005, the Environmental Protection Agency ("EPA") issued final amendments to its 1999 regional haze rule. These regulations are intended to protect visibility in national parks and wilderness areas ("Class I 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.

In September 2005, the Oklahoma Department of Environmental Quality ("ODEQ") informally notified affected utilities that they would be required to perform a study to determine their impact on visibility in Federal Class I areas. Affected utilities are those which have "Best Available Retrofit Technology ("BART") eligible sources" (sources built between 1962 and 1977). For OG&E these include various generating units at various generating stations. Regulations, however, allow an owner or operator of a BART-eligible source to request and obtain a waiver from BART if modeling shows no significant impact on visibility in nearby Class I areas. Therefore, OG&E initiated a preliminary modeling study that was completed in July 2006. Because the preliminary results indicated a significant impact from OG&E's Sooner, Muskogee, Seminole and Horseshoe Lake generating stations on visibility in Class I areas in both Oklahoma and Arkansas, more detailed modeling was performed. Based on results of modeling for the Seminole and Horseshoe Lake generating stations, OG&E submitted an application for waiver to the ODEQ on December 1, 2006. The ODEQ and the EPA approvals are required for any waiver. The ODEQ made a preliminary determination to accept the application for Horseshoe Lake and reject the application for Seminole. OG&E is continuing to discuss the Seminole application with the ODEQ. The Horseshoe Lake waiver will be included in the ODEQ state implementation plan that must be submitted for the EPA approval by December 17, 2007. It is not known whether approval for the state implementation plan will be granted by the EPA.

Proposed compliance determinations for affected units were required to be submitted to the ODEQ by March 30, 2007. The ODEQ will incorporate OG&E's, as well as other industry's compliance plans, into the state implementation plan which will then be submitted to the EPA. On March 30, 2007, OG&E submitted a determination to the ODEQ that an alternative compliance plan will achieve overall greater visibility improvement than BART eligible sources in the affected Class I areas and extends the timeline for compliance to 2018. The estimated cost for this plan is approximately $470 million. The alternative compliance plan includes installing semi-dry scrubbers on three of four affected coal units and low nitrogen oxide ("NOX") burner equipment on three natural gas units and four coal units. Although OG&E has submitted this lower cost plan, and believes it meets the intent of the regulation, the ODEQ and the EPA must approve the plan. OG&E has no guarantee that the compliance plan submitted will be approved. OG&E plans to spend approximately $5.4 million during 2007 related to the regional haze project. The cost to comply with the regional haze regulations could increase or decrease substantially based on the interpretation of the requirements by the ODEQ and the EPA, the availability of alternative control measures to achieve more cost effective visibility improvements, the availability of materials, labor force and the specific design criteria for OG&E's generating units. OG&E expects that any necessary environmental expenditures will qualify as part of a pre-approval plan to handle state and federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E's retail customers under House Bill 1910, which was enacted into law in May 2005.

With respect to the NOX regulations of the acid rain program, OG&E committed to meeting a 0.45 lbs/million British thermal unit ("MMBtu") NOX emission level in 1997 on all coal-fired boilers. As a result, OG&E was eligible to exercise its option to extend the effective date of the lower emission requirements from the year 2000 until 2008. OG&E's average NOX emissions from its coal-fired boilers for 2006 were approximately 0.33 lbs/MMBtu. The regulations require that OG&E achieve a NOX emission level of 0.40 lbs/MMBtu for these boilers beginning in 2008. It is expected that NOX emissions will be further reduced to 0.15 lbs/MMBtu by 2016, if the regional haze compliance plan discussed above is approved by the EPA. Further reductions in NOX emissions could be required if the ODEQ determines that such NOX emissions are impacting the air quality of the Tulsa or Oklahoma City metropolitan areas, or if Oklahoma becomes non-attainment with the fine particulate standard. Any of these scenarios would require significant capital and operating expenditures.

Water

OG&E has two Oklahoma Pollutant Discharge Elimination System (“OPDES”) permit renewals pending. OG&E expects that one of these renewal permits will be issued during the third quarter of 2007 while the other is expected to be issued during the fourth quarter of 2007. OG&E expects that these permits, when issued, will continue to be reasonable in their requirements, allow operational flexibility and provide reductions in operating costs. Additionally, OG&E filed an application with the state of Oklahoma during 2006 for a new wastewater discharge permit for one of its facilities. OG&E expects that the wastewater discharge permit for this facility will be issued in the third quarter of 2007.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the “best available technology” for minimizing environmental impacts. The EPA Section 316(b) rules for existing facilities became effective July 23, 2004. OG&E has engaged a consultant who has developed the required documentation for four OG&E facilities. These documents were submitted to the state agency on December 7, 2005 for review and approval. OG&E has also provided the state of Oklahoma with information and requests that, if approved by the state, may reduce the impact of the Section 316(b) rules on OG&E because OG&E’s position, if approved, would not require three of the four OG&E facilities to comply with the Section 316(b) rules. On January 25, 2007, a federal court reversed and remanded portions of the Section 316(b) rules to the EPA. The EPA is expected, by the end of the second quarter of 2007, to formally suspend the rules through publication in the Federal Register. In the interim, it is expected that all permits for existing facilities will be developed by the individual states using their best professional judgment. It is not clear what changes, if any, the EPA will ultimately make to the rules or how those changes may affect OG&E. Depending on the ultimate analysis and final determinations regarding the Section 316(b) rules, capital and/or operating costs may increase at any affected OG&E generating facility.

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. When appropriate, management consults with legal 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 Condensed Consolidated Financial Statements. Except as otherwise stated above, in Note 13 below, in Item 1 of Part II of this Form 10-Q, in Notes 17 and 18 of Notes to the Company’s Consolidated Financial Statements included in the Company’s Form 10-K for the year ended December 31, 2006 and in Item 3 of that report, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these 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.

13. 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, 2006 appropriately represent, in all material respects, the current status of any regulatory matters.

Completed Regulatory Matters

OCC Order Confirming Savings

The 2002 agreed-upon settlement of an OG&E rate case (“2002 Settlement Agreement”) required that, if OG&E did not acquire electric generation of not less than 400 megawatts (“MW”) (“New Generation”) by December 31, 2003, OG&E must credit $25.0 million annually (at a rate of 1/12 of $25.0 million per month for each month that the New Generation is not in place) to its Oklahoma customers beginning January 1, 2004 and continuing through December 31, 2006. In August 2003, OG&E signed an agreement to purchase a 77 percent interest in the 520 MW natural gas-fired combined cycle NRG McClain Station (“McClain Plant”), but due to a delay at the FERC, the acquisition was not completed by December 31, 2003. In the interim, OG&E entered into a power purchase agreement with the McClain Plant that delivered the savings guaranteed to OG&E’s customers. OG&E requested that the OCC confirm that the steps it had taken, including the power purchase agreement, were satisfying the customer savings obligation under the 2002 Settlement Agreement and that OG&E would not be required to begin crediting its customers. On April 28, 2004, the OCC issued an order confirming that OG&E was delivering savings to its customers as required under the 2002 Settlement Agreement. The order removed any uncertainty over whether the OCC believed OG&E had to reduce its rates, effective January 1, 2004, while it awaited action by the FERC on its application to purchase the McClain Plant. A party to the OCC proceeding appealed the OCC's order to the Oklahoma Supreme Court. The appeal was denied and the OCC order is considered final. OG&E has filed reports with the OCC for the months of January 2004 through December 2006 supporting the savings from the McClain Plant. OG&E expects to file an application with the OCC in the second quarter of 2007 supporting its compliance with the 2002 Settlement Agreement. OG&E expects the OCC to issue an order by the end of 2007 in this matter.

Acquisition of Power Plant

On July 9, 2004, OG&E completed the acquisition of a 77 percent interest in the McClain Plant. This transaction was intended to satisfy the requirement in the 2002 Settlement Agreement to acquire New Generation.

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 (January 1, 2004 through December 31, 2006), 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 subsequent to the end of the 36-month period. At this time, OG&E believes that it achieved at least $75.0 million in savings during this period. As discussed above, OG&E expects to file an application with the OCC in the second quarter of 2007 supporting its compliance with the 2002 Settlement Agreement. OG&E expects the OCC to issue an order by the end of 2007 in this matter.

Security Enhancements

On April 8, 2002, OG&E filed a joint application with the OCC Staff requesting approval for security investments and a rider to recover these costs from the ratepayers. On October 28, 2004, all parties signed a joint stipulation that contains the OCC Staff's recommendations and authorizes up to a $5 million annual recovery from OG&E's customers for security enhancement. On December 21, 2004, the OCC issued an order approving the stipulation which included a security rider. OG&E implemented the security rider with the first billing period in July 2006 and began charging OG&E's Oklahoma customers approximately $2.4 million annually. In compliance with the OCC order, in October 2006, OG&E filed a report regarding the recovery of the security costs through the authorized recovery rider for the period from July 1, 2006 to September 30, 2006. The OCC authorized tariff provides that the security rider may be updated quarterly. In December 2006, OG&E updated the security rider to recover approximately $2.9 million annually beginning with the first billing cycle in January 2007. OG&E also filed an application with the OCC on December 15, 2006 to amend its security plan to seek approval of approximately $7.6 million of cost increases related to the expanded scope of previously authorized projects and approximately $10.9 million for new security projects. If approved by the OCC, the annual revenue requirement associated with the $18.5 million of capital expenditures would increase recovery under the security rider by approximately $2.7 million. On March 30, 2007, the OCC Staff filed testimony recommending the OCC approve approximately $17.6 million of the security capital expenditures and the associated revenue requirement of approximately $2.6 million. The current procedural schedule provides for a hearing beginning on May 30, 2007. OG&E expects the OCC to issue an order in the third quarter of 2007 in this matter.

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2005

The OCC routinely audits activity in OG&E's fuel adjustment clause for each calendar year. In October 2006, the OCC Staff filed an application for a review of OG&E's 2005 fuel adjustment clause. A procedural schedule is expected to be issued in the second quarter of 2007.

Cogeneration Credit Rider

On September 17, 2004, OG&E filed an application and testimony with the OCC requesting a cogeneration credit rider. The requested rider reduces cogeneration charges to customers because of decreasing cogeneration payments made by OG&E beginning January 2005. The cogeneration credit rider is necessary because amounts currently recovered from customers in base rates include historically higher cogeneration payments. OG&E's cogeneration credit rider has been updated and approved by the OCC in December of each year through December 2006 and any over/under recovery of the cogeneration credit rider in the current year and prior periods has been automatically included in the next year's rider. OG&E's current cogeneration credit rider expires December 31, 2007. The 2007 cogeneration credit rider, filed with the OCC, of approximately $80.7 million is partially offset by the prior year under recovery of approximately $2.5 million. OG&E expects to file an application with the OCC in late 2007 to request a new cogeneration credit rider for years after 2007.

OG&E Wind Power Filing

In January 2007, OG&E's 120 MW wind farm ("Centennial") in northwestern Oklahoma was fully in service. From January 1, 2007 through March 31, 2007, OG&E spent approximately $28.3 million related to the Centennial wind farm for total expenditures in 2006 and 2007 of approximately $199.4 million. The OCC previously issued its order approving a settlement agreement relating to the Centennial wind power contract and authorizing a recovery rider for up to $205 million in construction costs and allowance for funds used during construction. The settlement also indicated that OG&E shall file for a general rate review during 2009 that will permit the OCC to issue an order no later than December 31, 2009 placing the Centennial wind farm in OG&E's rate base. Pursuant to the settlement agreement, OG&E sent notice to the OCC on January 17, 2007 informing the OCC that the Centennial wind farm was operational, which triggered the recovery rider for the first billing cycle in February 2007. The recovery rider is designed to recover approximately $22.6 million for the calendar year of 2007, which amount will decline over the life of the facility. Because the wind farm rider was implemented in February 2007, OG&E expects to recover approximately $20.7 million under the rider during the remaining 11 months of 2007. OG&E expects the recovery rider to remain in effect through late 2009. As explained below, the recent rate order from the APSC allows for the recovery of the portion of the Centennial wind farm allocable to OG&E's customers in Arkansas.

OG&E Arkansas Rate Case Filing

On July 28, 2006, OG&E filed with the APSC an application for an annual rate increase of approximately $13.5 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant, the Centennial wind power project and the costs of electric system expansion and upgrades based on a return on equity of 11.75 percent. On November 29, 2006, OG&E reached a settlement with the other parties in this case for an annual rate increase of approximately $5.4 million. In the settlement agreement, the parties also agreed that OG&E would be allowed to recover the full Arkansas portion of the Centennial wind farm. On January 5, 2007, the APSC approved the settlement and issued a rate order that provides for a $5.4 million annual increase in OG&E's electric rates and a 10.0 percent return on equity. The new Arkansas rates became effective in February 2007.

Pending Regulatory Matters

Proposed Construction of Power Plant

On July 18, 2006, the Company announced plans for OG&E to partner with American Electric Power's subsidiary, Public Service Company of Oklahoma ("PSO"), and the Oklahoma Municipal Power Authority ("OMPA") to build a new 950 MW coal unit at OG&E's existing Sooner plant location near Red Rock, Oklahoma. The estimated $1.8 billion project is the result of PSO's December 2005 request for proposals in which it sought bids for up to 600 MW's of new base load generation to be available to PSO. The unit, to be called Red Rock, is expected to be one of the cleanest of its size using coal from the Powder River Basin, which is located near Gillette, Wyoming. OG&E will operate the facility and expects to spend approximately $759 million in construction costs related to its 42 percent ownership percentage in the project and approximately $30 million in transmission costs for the project. PSO will own 50 percent and the OMPA will own eight percent. On December 1, 2006, OG&E submitted an application to the ODEQ for an air permit for the Red Rock plant. OG&E is seeking to have the air permit approved by the ODEQ by August 1, 2007. OG&E expects construction to begin in 2007 and is targeting the completion of the power plant in the 2011/2012 timeframe. OG&E filed an application with the OCC on January 17, 2007 asking the OCC to find that its portion of the construction costs are prudent and that a recovery mechanism should be established to recover OG&E's overall cost of capital on the investment during the construction period. The OCC rules provide that the OCC has up to 240 days to issue an order determining OG&E's pre-approval request; however, OG&E's application requested that the OCC issue an order by July 20, 2007. On March 1, 2007, the OCC issued an order consolidating OG&E's application with two applications by PSO which seek pre-approval of proposed generation facilities, including PSO's portion of Red Rock. The OCC order also adopted a procedural schedule which includes a hearing on the consolidated applications in July 2007. Absent a settlement, the earliest OG&E expects an order from the OCC is late August 2007. The project is contingent upon numerous factors, including the successful completion of contract negotiations and the necessary regulatory and environmental approvals. Under the construction, ownership and operating agreement between OG&E, PSO and the OMPA, the parties could incur up to $60 million (of which approximately $25 million would be borne by OG&E) prior to the receipt of acceptable regulatory approvals and permits. If such approvals and permits were not obtained and the Red Rock project was abandoned, the Company can provide no assurance that these expenditures incurred by OG&E would be recoverable in future rates. To date, OG&E has incurred approximately $4.2 million of capitalized costs associated with the Red Rock project.

FERC Audit

On May 29, 2006, the FERC notified OG&E that it was commencing an audit to determine whether and how OG&E is complying with: (i) its Open Access Transmission Tariff; (ii) requirements of its market-based rate authorization; (iii) Standards of Conduct and Open Access Same-Time Information System; and (iv) wholesale fuel adjustment clause tariff and other requirements contained in the FERC regulations. Over the past several years, the FERC has conducted numerous audits of utilities across the country to ensure regulatory compliance. OG&E cannot predict the final outcome of this audit or its timing.

Southwest Power Pool

The SPP filed on June 15, 2005, Docket No. ER05-1118, to create a real-time, offer-based energy imbalance service market that will require cash settlements for over or under generation. Market participants, including OG&E, will be required to submit resource plans and can submit offer curves for each resource available for dispatch. In addition, the SPP may order certain dispatching of generating units and has implemented a market monitoring plan that provides a clear set of rules, the potential consequences if the rules are violated and the areas in which an independent market monitor will examine and report. On March 20, 2006, the FERC issued an order that conditionally accepted a portion of the filing and suspended and rejected other portions of the filing. After several delays, the SPP Board of Directors voted to implement the energy imbalance service market no earlier than February 1, 2007. The SPP filed a certification of readiness to the FERC on January 18, 2007 that addressed issues raised by intervenors to the proceeding. The SPP energy imbalance service market began operations on February 1, 2007. As one condition to participation in the energy imbalance service market, OG&E, as well as other balancing authorities in the SPP, were required to submit open access tariff schedules setting forth the rates, terms and conditions for the provision of emergency energy service. OG&E submitted the required schedule on September 13, 2006, in Docket No. ER06-1488-000. On January 31, 2007, the FERC issued an order conditionally accepting OG&E's proposed emergency energy schedule, subject to OG&E submitting, within 30 days, a compliance filing making certain revisions required by the FERC. On March 6, 2007, OG&E filed its compliance filing.

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 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 new interim tests. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 that applied the interim tests to OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but did not pass the market share screen in OG&E's control area. OG&E and OERI provided an explanation as to why their failure of the market share screen in OG&E's control area should not be viewed as an indication that they can exercise generation market power.

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 established hearing procedures to investigate whether OG&E and OERI may continue to sell power at market-based rates in OG&E's control area. The order established a rebuttable presumption that OG&E and OERI have the ability to exercise market power in OG&E's control area. OG&E and OERI were 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. On August 8, 2005, OG&E and OERI informed the FERC that they will: (i) adopt the FERC default rate mechanism for sales of one week or less to loads that sink in OG&E's control area; and (ii) commit not to enter into any sales with a duration of between one week and one year to loads that sink in OG&E's control area. OG&E and OERI also informed the FERC that any new agreements for long-term sales (one year or longer in duration) to loads that sink in OG&E's control area will be filed with the FERC and that OG&E and OERI will not make such sales under their respective market-based rate tariffs. On January 20, 2006, the FERC issued a Notice of Institution of Proceeding and Refund Effective Date for the purpose of establishing the date from which any subsequent market-based sales would be subject to refund in the event the FERC concludes after investigation that the rates for such sales are not just and reasonable. The refund effective date was March 27, 2006.

On March 21, 2006, the FERC issued an order conditionally accepting OG&E's and OERI's proposal to mitigate the presumption of market power in OG&E's control area. First, the FERC accepted the additional information related to first-tier markets submitted by OG&E and OERI, and concluded that OG&E and OERI satisfy the FERC's generation market power standard for directly interconnected first-tier control areas. Second, the FERC directed the Company to make certain revisions to its mitigation proposal and file a cost-based rate tariff for short-term sales (one week or less) made within

OG&E's control area. The FERC also expanded the scope of the proposed mitigation to all sales made within OG&E's control area (instead of only to sales sinking to load within OG&E's control area). On April 20, 2006, the Company submitted: (i) a compliance filing containing the specified revisions to the Company's market-based rate tariffs and the new cost-based rate tariff; and (ii) a request for rehearing asking the FERC to reconsider its expanded mitigation directive contained in the March 21, 2006 order. On May 22, 2006, the FERC issued a tolling order that effectively provided the FERC additional time to consider the April 20, 2006 rehearing request. On July 25, 2006 and August 25, 2006, pursuant to a FERC March 20, 2006 order, OG&E and OERI filed revisions to their market-based rate tariffs to allow them to sell energy imbalance service into the wholesale markets administered by the SPP at market-based rates. The FERC has not yet acted on OG&E's April 20, 2006, July 25, 2006 or August 25, 2006 filings. On February 6, 2007, OG&E and OERI submitted to the FERC a change in status report notifying the FERC that OG&E has placed into service OG&E's Centennial wind farm, a wind farm with a nameplate capacity rating of 120 MW. OG&E and OERI explained that adding this capacity was not material to the FERC's grant of market-based rate status to OG&E and OERI. On March 9, 2007, the FERC accepted OG&E's and OERI's change of status filing.

North American Electric Reliability Council

The Energy Policy Act of 2005 gave the FERC authority to establish mandatory electric reliability rules enforceable with monetary penalties. The FERC has approved the North American Electric Reliability Council ("NERC") as the Electric Reliability Organization ("ERO") for North America and delegated to it the development and enforcement of electric transmission reliability rules. On April 19, 2007, the FERC approved the SPP as a Regional Entity whose primary function is to ensure that the NERC is in compliance with reliability standards. On March 16, 2007, the FERC approved 83 mandatory NERC reliability standards. These reliability standards become effective June 4, 2007. The Company is subject to periodic NERC compliance audits and cannot predict the outcome of those audits.

State Legislative Initiatives

Oklahoma

In the 2007 Oklahoma legislative session, legislation was proposed discussing that fuel or gas removed from storage shall be accounted for using the weighted-average cost method of accounting for inventory rather than using the last-in, first-out cost method. This legislation is proposed to be effective January 1, 2008. The Company cannot predict whether, or in what form, this bill will be enacted into law.

14. 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, 2006.

	March 31, 2007		December 31, 2006	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 9.4**	**$ 9.4**	$ 42.7	$ 42.7
Interest Rate Swaps	---	---	0.9	0.9
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 7.4**	**$ 7.4**	$ 10.3	$ 10.3

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.

In accordance with FASB Interpretation No. 39 (As Amended), "Offsetting of Amounts Related to Certain Contracts an interpretation of APB Opinion No. 10 and FASB Statement No. 105," fair value amounts recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the consolidated balance sheet.

In the Company's Condensed Consolidated Balance Sheets at March 31, 2007 and December 31, 2006, the fair value of transactions with the same counterparty is presented on a gross basis, consistent with past practice. However, OERI has energy trading contracts with set off provisions with various counterparties. If these transactions with the same counterparty were presented on a net basis in the Condensed Consolidated Balance Sheets, Price Risk Management assets and liabilities would be approximately $7.4 million and $5.3 million, respectively, at March 31, 2007, and would be approximately $40.0 million and $6.7 million, respectively, at December 31, 2006.

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 related services for 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. OG&E 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. In May 2006, Enogex Gas Gathering, L.L.C. ("Gathering"), a wholly-owned subsidiary of Enogex Inc., sold certain gas gathering assets in the Kinta, Oklahoma, area, which have been reported as discontinued operations in the Company's Condensed Consolidated Financial Statements (see "Results of Operations – Enogex – Discontinued Operations" for a further discussion).

Overview

Summary of Operating Results

Quarter ended March 31, 2007 as compared to quarter ended March 31, 2006

The Company reported net income of approximately $17.2 million, or $0.19 per diluted share, during the three months ended March 31, 2007, as compared to approximately $24.9 million, or $0.27 per diluted share, during the three months ended March 31, 2006. The decrease in net income during the three months ended March 31, 2007 as compared to the same period in 2006 was primarily due to:

- OG&E reported net income of approximately $1.9 million, or $0.02 per diluted share of the Company's common stock, during the three months ended March 31, 2007, as compared to a net loss of approximately $1.1 million, or $0.01 per diluted share, during the three months ended March 31, 2006;
- Enogex's operations, including discontinued operations, reported net income of approximately $15.5 million, or $0.17 per diluted share of the Company's common stock (all attributable to continuing operations), during the three months ended March 31, 2007, as compared to approximately $27.0 million,

or $0.29 per diluted share (of which $0.01 per diluted share was attributable to discontinued operations), during the three months ended March 31, 2006; and

- a net loss at the holding company of approximately $0.2 million, or less than $0.01 per diluted share, during the three months ended March 31, 2007, as compared to a net loss of approximately $1.0 million, or $0.01 per diluted share, during the three months ended March 31, 2006, primarily due to an increase in other income during the three months ended March 31, 2007 related to the Company's deferred compensation plan and restoration of retirement income plan and lower interest expense during the three months ended March 31, 2007 primarily due to lower commercial paper fees resulting from no commercial paper borrowings in the first quarter of 2007.

Enogex's net income for the three months ended March 31, 2007 of approximately $15.5 million discussed above included a loss of approximately $4.1 million at OGE Energy Resources, Inc. ("OERI") resulting from recording hedges associated with the Cheyenne Plains transportation contract at market value on March 31, 2007. The offsetting gains from physical utilization of the transportation capacity are expected to be realized during the remainder of 2007. Also, at March 31 2007, Enogex recorded a loss of approximately $0.8 million resulting from recording storage hedges at market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2008.

Recent Developments

OG&E Wind Power Filing

In January 2007, OG&E's 120 megawatt ("MW") wind farm ("Centennial") in northwestern Oklahoma was fully in service. From January 1, 2007 through March 31, 2007, OG&E spent approximately $28.3 million related to the Centennial wind farm for total expenditures in 2006 and 2007 of approximately $199.4 million. The OCC previously issued its order approving a settlement agreement relating to the Centennial wind power contract and authorizing a recovery rider for up to $205 million in construction costs and allowance for funds used during construction. The settlement also indicated that OG&E shall file for a general rate review during 2009 that will permit the OCC to issue an order no later than December 31, 2009 placing the Centennial wind farm in OG&E's rate base. Pursuant to the settlement agreement, OG&E sent notice to the OCC on January 17, 2007 informing the OCC that the Centennial wind farm was operational, which triggered the recovery rider for the first billing cycle in February 2007. The recovery rider is designed to recover approximately $22.6 million in the first year of operations, which amount will decline over the life of the facility. Because the wind farm rider was implemented in February 2007, OG&E expects to recover approximately $20.7 million under the rider during the remaining 11 months of 2007. OG&E expects the recovery rider to remain in effect through late 2009. As explained below, the recent rate order from the APSC allows for the recovery of the portion of the Centennial wind farm allocable to OG&E's customers in Arkansas.

OG&E Arkansas Rate Case Filing

On July 28, 2006, OG&E filed with the APSC an application for an annual rate increase of approximately $13.5 million to recover, among other things, its investment in, and the operating expenses of, OG&E's 77 percent interest in the 520 MW natural gas-fired combined cycle NRG McClain Station, the Centennial wind power project and the costs of electric system expansion and upgrades based on a return on equity of 11.75 percent. On November 29, 2006, OG&E reached a settlement with the other parties in this case for an annual rate increase of approximately $5.4 million. In the settlement agreement, the parties also agreed that OG&E would be allowed to recover the full Arkansas portion of the Centennial wind farm. On January 5, 2007, the APSC approved the settlement and issued a rate order that provides for a $5.4 million annual increase in OG&E's electric rates and a 10.0 percent return on equity. The new Arkansas rates became effective in February 2007.

Proposed Construction of Power Plant

As discussed above, OG&E has entered into a contract with American Electric Power's subsidiary, Public Service Company of Oklahoma ("PSO"), and the Oklahoma Municipal Power Authority ("OMPA") to build a new 950 MW coal unit at OG&E's existing Sooner plant location near Red Rock, Oklahoma. The estimated $1.8 billion project is the result of PSO's December 2005 request for proposals in which it sought bids for up to 600 MW's of new base load generation to be available to PSO. The unit, to be called Red Rock, is expected to be one of the cleanest of its size using coal from the Powder River Basin, which is located near Gillette, Wyoming. OG&E will operate the facility and expects to spend approximately $759 million in construction costs related to its 42 percent ownership percentage in the project and approximately $30 million in transmission costs for the project. PSO will own 50 percent and the OMPA will own eight percent. On December 1, 2006, OG&E submitted an application to the Oklahoma Department of Environmental Quality

(“ODEQ”) for an air permit for the Red Rock plant. OG&E is seeking to have the air permit approved by the ODEQ by August 1, 2007. OG&E expects construction to begin in 2007 and is targeting the completion of the power plant in the 2011/2012 timeframe. OG&E filed an application with the OCC on January 17, 2007 asking the OCC to find that its portion of the construction costs are prudent and that a recovery mechanism should be established to recover OG&E’s overall cost of capital on the investment during the construction period. The OCC rules provide that the OCC has up to 240 days to issue an order determining OG&E’s pre-approval request; however, OG&E’s application requested that the OCC issue an order by July 20, 2007. On March 1, 2007, the OCC issued an order consolidating OG&E’s application with two applications by PSO which seek pre-approval of proposed generation facilities, including PSO’s portion of Red Rock. The OCC order also adopted a procedural schedule which includes a hearing on the consolidated applications in July 2007. Absent a settlement the earliest OG&E expects an order from the OCC is late August 2007. The project is contingent upon numerous factors, including the successful completion of contract negotiations and the necessary regulatory and environmental approvals. Under the construction, ownership and operating agreement between OG&E, PSO and the OMPA, the parties could incur up to $60 million (of which approximately $25 million would be borne by OG&E) prior to the receipt of acceptable regulatory approvals and permits. If such approvals and permits were not obtained and the Red Rock project was abandoned, the Company can provide no assurance that these expenditures incurred by OG&E would be recoverable in future rates. To date, OG&E has incurred approximately $4.2 million of capitalized costs associated with the Red Rock project.

2007 Outlook

The Company’s 2007 earnings guidance is between $213 million to $231 million of income from continuing operations, or $2.30 to $2.50 per diluted share, as shown in the table below, which excludes any gains on asset sales and assumes approximately 92.5 million average diluted shares outstanding. See “2007 Outlook” in the Company’s Form 10-K for the year ended December 31, 2006 for a description of the underlying assumptions related to the earnings guidance for OG&E, Enogex and the holding company.

	2007 Earnings Guidance	
(In millions, except per share data)	Dollars	Diluted EPS
OG&E	$154 - $162	$1.67 - $1.75
Enogex	$63 - $72	$0.68 - $0.78
Holding Company	($3) - ($4)	($0.03) - ($0.05)
Total	$213 - $231	$2.30 - $2.50

Results of Operations

The following discussion and analysis presents factors that affected the Company’s consolidated results of operations for the three months ended March 31, 2007 as compared to the same period in 2006 and the Company’s consolidated financial position at March 31, 2007. 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 March 31,	
(In millions, except per share data)	**2007**	2006
Operating income	**$ 46.2**	$ 51.8
Net income	**$ 17.2**	$ 24.9
Basic average common shares outstanding	**91.5**	90.6
Diluted average common shares outstanding	**92.4**	91.6
Basic earnings per average common share	**$ 0.19**	$ 0.27
Diluted earnings per average common share	**$ 0.19**	$ 0.27
Dividends declared per share	**$ 0.34**	$ 0.3325

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 the cost of capital and income taxes.

Operating Income (Loss) by Business Segment

	Three Months Ended March 31,	
(In millions)	**2007**	2006
OG&E (Electric Utility)	**$ 16.0**	$ 9.8
Enogex (Natural Gas Pipeline)	**30.2**	42.1
Other Operations (A)	**---**	(0.1)
Consolidated operating income	**$ 46.2**	$ 51.8

(A) Other Operations primarily includes unallocated corporate expenses, interest expense on commercial paper, interest expense on long-term debt and consolidating eliminations.

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

(Dollars in millions)	Three Months Ended March 31, **2007**	2006
Operating revenues	**$ 340.7**	$ 374.0
Cost of goods sold	**199.9**	237.7
Gross margin on revenues	**140.8**	136.3
Other operation and maintenance	**74.2**	79.7
Depreciation	**35.4**	33.1
Taxes other than income	**15.2**	13.7
Operating income	**16.0**	9.8
Interest income	**---**	1.0
Other income	**1.3**	0.1
Other expense	**0.6**	1.0
Interest expense	**15.6**	13.7
Income tax benefit	**0.8**	2.7
Net income (loss)	**$ 1.9**	$ (1.1)
Operating revenues by classification		
Residential	**$ 134.7**	$ 137.9
Commercial	**76.2**	88.4
Industrial	**41.3**	53.3
Oilfield	**27.8**	32.1
Public authorities	**31.3**	37.1
Sales for resale	**13.9**	14.9
System sales revenues	**325.2**	363.7
Off-system sales revenues	**9.3**	0.5
Other	**6.2**	9.8
Total operating revenues	**$ 340.7**	$ 374.0
MWH (A) sales by classification (in millions)		
Residential	**2.0**	1.8
Commercial	**1.4**	1.3
Industrial	**1.0**	1.1
Oilfield	**0.7**	0.6
Public authorities	**0.6**	0.6
Sales for resale	**0.3**	0.4
System sales	**6.0**	5.8
Off-system sales	**0.3**	---
Total sales	**6.3**	5.8
Number of customers	**758,244**	748,695
Average cost of energy per KWH (B) - cents		
Fuel	**2.634**	3.538
Fuel and purchased power	**2.964**	3.839
Degree days (C)		
Heating		
Actual	**1,669**	1,499
Normal	**1,963**	1,963
Cooling		
Actual	**43**	31
Normal	**8**	8

(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 March 31, 2007 as compared to quarter ended March 31, 2006

OG&E's operating income increased approximately $6.2 million during the three months ended March 31, 2007 as compared to the same period in 2006 primarily due to higher gross margin on revenues ("gross margin") and lower operating expenses partially offset by higher depreciation expense and taxes other than income.

Gross margin, which is operating revenues less cost of goods sold, was approximately $140.8 million during the three months ended March 31, 2007 as compared to approximately $136.3 million during the same period in 2006, an increase of approximately $4.5 million, or 3.3 percent. The gross margin increased primarily due to:

- higher rates as a result of the Centennial wind farm rider, security rider and Arkansas rate case, which increased the gross margin by approximately $4.7 million;
- cooler weather in OG&E's service territory resulting in an approximate 11 percent increase in heating degree days compared to the first quarter of 2006, which increased the gross margin by approximately $3.1 million;
- new customer growth in OG&E's service territory, which increased the gross margin by approximately $2.9 million; and
- higher capacity charges associated with industrial customers in OG&E's service territory, which increased the gross margin by approximately $0.5 million.

These increases in the gross margin were partially offset by OG&E's filing of amended tariffs with the OCC in January 2007 to cease collection of additional fuel-related revenues that were not intended by OG&E's 2005 rate order, which caused the gross margin to be approximately $7.8 million lower than the first quarter of 2006. See Note 1 of Notes to Consolidated Financial Statements in the Company's 2006 Form 10-K for a further discussion.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $159.7 million during the three months ended March 31, 2007 as compared to approximately $184.7 million during the same period in 2006, a decrease of approximately $25.0 million, or 13.5 percent, primarily due to lower natural gas prices. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. Purchased power costs were approximately $40.2 million during the three months ended March 31, 2007 as compared to approximately $53.0 million during the same period in 2006, a decrease of approximately $12.8 million, or 24.2 percent. This decrease was primarily due to lower cogeneration purchases from PowerSmith Cogeneration Project, L.P. as a result of the Oklahoma City Dayton tire plant closing in December 2006 and OG&E's entrance into the energy imbalance service market on February 1, 2007 (see Note 13 of Notes to Condensed Consolidated Financial Statements for a further discussion).

Other operating and maintenance expenses were approximately $74.2 million during the three months ended March 31, 2007 as compared to approximately $79.7 million during the same period in 2006, a decrease of approximately $5.5 million, or 6.9 percent. The decrease in other operating and maintenance expenses was primarily due to:

- a decrease in professional services expense of approximately $3.0 million due to the timing of legal expenses;
- lower salaries, wages and other employee benefits expense of approximately $1.5 million;
- an increase in capitalized labor and transportation expenses in 2007 of approximately $0.9 million; and
- lower allocations from the holding company of approximately $0.8 million primarily due to a decrease in incentive compensation.

These decreases in other operating and maintenance expenses were partially offset by higher bad debt expense of approximately $0.7 million.

Depreciation expense was approximately $35.4 million during the three months ended March 31, 2007 as compared to approximately $33.1 million during the same period on 2006, an increase of approximately $2.3 million, or 6.9 percent, primarily due to the Centennial wind farm being placed in service during January 2007.

Taxes other than income were approximately $15.2 million during the three months ended March 31, 2007 as compared to approximately $13.7 million in 2006, an increase of approximately $1.5 million, or 10.9 percent, primarily due to increased ad valorem taxes.

Interest income was approximately $1.0 million during the three months ended March 31, 2006 with no interest income during the same period in 2007. The decrease was due to interest income earned on fuel under recoveries during the three months ended March 31, 2006 while there was a fuel over recovery balance during the same period in 2007.

Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating income. Other income was approximately $1.3 million during the three months ended March 31, 2007 as compared to approximately $0.1 million during the same period in 2006, an increase of approximately $1.2 million, primarily due to an increase in income related to the guaranteed flat bill tariff during 2007 resulting from more customers participating in this plan from April 1, 2006 through March 31, 2007.

Interest expense was approximately $15.6 million during the three months ended March 31, 2007 as compared to approximately $13.7 million during the same period in 2006, an increase of approximately $1.9 million, or 13.9 percent. The increase in interest expense was primarily due to:

- increased interest of approximately $1.0 million associated with the interest due to customers related to the fuel over recovery balance in the first quarter of 2007;
- increased interest due to a decrease in the allowance for borrowed funds used during construction of approximately $0.4 million; and
- increased interest of approximately $0.3 million due to the issuance of $220.0 million of long-term debt in January 2006.

Income tax benefit was approximately $0.8 million during the three months ended March 31, 2007 as compared to approximately $2.7 million during the same period in 2006, a decrease of approximately $1.9 million, or 70.4 percent primarily due to higher pre-tax income for OG&E.

Enogex – Continuing Operations

	Three Months Ended March 31,	
(Dollars in millions)	**2007**	2006
Operating revenues	**$ 557.8**	$ 763.2
Cost of goods sold	**484.0**	678.0
Gross margin on revenues	**73.8**	85.2
Other operation and maintenance	**27.8**	28.6
Depreciation	**11.3**	10.2
Taxes other than income	**4.5**	4.3
Operating income	**30.2**	42.1
Interest income	**2.6**	2.5
Other income	**0.3**	6.0
Other expense	**0.1**	---
Interest expense	**8.1**	8.1
Income tax expense	**9.4**	16.3
Income from continuing operations	**$ 15.5**	$ 26.2
New well connects (includes wells behind central receipt points) (A)	**99**	77
New well connects (excludes wells behind central receipt points)	**46**	52
Gathered volumes – TBtu/d (B)	**0.99**	0.96
Incremental transportation volumes – TBtu/d	**0.39**	0.41
Total throughput volumes – TBtu/d	**1.38**	1.37
Natural gas processed – TBtu/d	**0.52**	0.52
Natural gas liquids sold (keep-whole) – million gallons	**51**	52
Natural gas liquids sold (purchased for resale) – million gallons	**27**	22
Natural gas liquids sold (percentage of liquids) – million gallons	**4**	3
Total natural gas liquids sold – million gallons	**82**	77
Average sales price per gallon	**$ 0.858**	$ 0.912

(A) As reported to the Company by third parties.
(B) Trillion British thermal units per day.

Quarter ended March 31, 2007 as compared to quarter ended March 31, 2006

Enogex's operating revenues and cost of goods sold decreased during the three months ended March 31, 2007 approximately $205.4 million, or 26.9 percent, and $194.0 million, or 28.6 percent, respectively, as compared to the same period in 2006. These decreases are attributable primarily to lower revenues and related costs in Enogex's marketing business, reflecting the implementation of Enogex's strategy in 2006 to have its marketing business reduce its trading activities by focusing its marketing efforts on Enogex's assets. Enogex's operating income decreased approximately $11.9 million during the three months ended March 31, 2007 as compared to the same period in 2006 primarily due to lower gross margins in Enogex's transportation and storage business, largely as a result of increased imbalance expense, and lower gross margins in Enogex's marketing business, largely due to losses on economic hedges recorded at market value in the first quarter of 2007, partially offset by higher gross margins in Enogex's gathering and processing business. Also contributing to the decrease in operating income was higher depreciation expense partially offset by lower operating and maintenance expense.

Transportation and storage contributed approximately $30.0 million of Enogex's gross margin during the three months ended March 31, 2007 as compared to approximately $40.8 million during the same period in 2006, a decrease of approximately $10.8 million, or 26.5 percent. The gross margin decreased primarily due to:

- an imbalance expense of approximately $4.2 million during the first quarter of 2007 as the result of an increase in the net imbalance liability, as compared to the first quarter of 2006 in which the transportation and storage business recognized approximately a $5.9 million benefit from the reduction of the net imbalance liability, of which approximately $3.2 million was due to the transfer of certain imbalance liabilities to the gathering and processing business during the first quarter of 2006; and
- lower margins on natural gas sales from lower natural gas prices and lower volumes in 2007, which decreased the gross margin by approximately $1.2 million.

These decreases in the transportation and storage gross margin were partially offset by a reduction in the Company's over recovered position in the East zone in the first quarter of 2007 as compared to the first quarter of 2006, which increased the gross margin by approximately $1.3 million.

Gathering and processing contributed approximately $41.9 million of Enogex's gross margin during the three months ended March 31, 2007 as compared to approximately $38.2 million during the same period in 2006, an increase of approximately $3.7 million, or 9.7 percent. The gathering and processing gross margin increased primarily due to:

- reduced imbalance expense resulting from the recognition in the first quarter of 2006 of approximately a $3.2 million imbalance liability upon the transfer of imbalances previously recognized in the transportation and storage business coupled with approximately a $0.2 million net imbalance liability increase in 2007 as compared to 2006;
- increased net keep-whole margins primarily due to higher commodity spreads in 2007 as compared to 2006, which increased the gross margin by approximately $1.5 million;
- new percentage of liquids contracts in 2007, which increased the gross margin by approximately $0.8 million;
- increased low pressure fees due to new business growth in 2007, which increased the gross margin by approximately $0.7 million; and
- increased condensate recoveries due to higher prices and increased demand from colder temperatures in 2007, which increased the gross margin by approximately $0.6 million.

These increases in the gathering and processing gross margin were partially offset by a reduction in the Company's over recovered position of approximately $3.2 million in the first quarter of 2006 as compared to a reduction of approximately $0.1 million in the first quarter of 2007, which resulted in a decreased gross margin in the first quarter of 2007 of approximately $3.1 million as compared to 2006.

Marketing contributed approximately $1.9 million of Enogex's gross margin during the three months ended March 31, 2007 as compared to approximately $6.2 million during the same period in 2006, a decrease of approximately $4.3 million, or 69.4 percent. The gross margin decreased primarily due to:

- losses on economic hedges associated with transportation contracts from recording these hedges at market value on March 31, 2007, which decreased the gross margin by approximately $13.4 million; and

- losses on economic hedges of natural gas storage inventory from recording these hedges at market value on March 31, 2007, which decreased the gross margin by approximately $4.9 million.

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

- gains on physical storage activity partially offset by higher fees, which increased the gross margin by approximately $6.9 million;
- realized gains from physical activity on transportation contracts, which increased the gross margin by approximately $4.4 million; and
- a lower of cost or market adjustment related to natural gas in storage during the first quarter of 2006, which increased the 2007 gross margin by approximately $2.1 million.

Enogex's other operating and maintenance expenses were approximately $27.8 million during the three months ended March 31, 2007 as compared to approximately $28.6 million during the same period in 2006, a decrease of approximately $0.8 million, or 2.8 percent. The decrease in other operating and maintenance expenses was primarily due to lower outside services expense of approximately $1.8 million primarily related to a delay in projects due to inclement weather in 2007 as well as the write-off of costs associated with a business development project in 2006. This decrease in other operating and maintenance expenses was partially offset by higher salaries, wages and other employee benefits expense of approximately $1.4 million primarily due to incentive compensation and hiring additional employees to support business growth.

Depreciation expense was approximately $11.3 million during the three months ended March 31, 2007 as compared to approximately $10.2 million during the same period in 2006, an increase of approximately $1.1 million, or 10.8 percent, primarily due to new assets placed into service in 2006.

Other income was approximately $0.3 million during the three months ended March 31, 2007 as compared to approximately $6.0 million during the same period in 2006, a decrease of approximately $5.7 million, or 95.0 percent, primarily due to a litigation settlement of approximately $5.2 million in 2006.

Income tax expense was approximately $9.4 million during the three months ended March 31, 2007 as compared to approximately $16.3 million during the same period in 2006, a decrease of approximately $6.9 million, or 42.3 percent, primarily due to lower pre-tax income for Enogex.

For the three months ended March 31, 2007, Enogex's net income of approximately $15.5 million included a loss of approximately $4.1 million at OERI resulting from recording hedges associated with the Cheyenne Plains transportation contract at market value on March 31, 2007. The offsetting gains from physical utilization of the transportation capacity are expected to be realized during the remainder of 2007. Also, at March 31, 2007, Enogex recorded a loss of approximately $0.8 million resulting from recording storage hedges at market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2008. During the three months ended March 31, 2007, Enogex had no items that it does not consider to be reflective of the ongoing profitability of its business.

For the three months ended March 31, 2006, Enogex's net income, including the discontinued operations discussed below under the caption "Enogex – Discontinued Operations," was approximately $27.0 million. During the three months ended March 31, 2006, Enogex had an increase in net income of approximately $4.3 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:

- litigation settlement of approximately $3.2 million;
- income from discontinued operations of approximately $0.8 million; and
- a gain from the sale of a small gathering section of Enogex's pipeline of approximately $0.3 million.

Enogex – Discontinued Operations

In March 2006, Enogex announced that its wholly-owned subsidiary, Gathering, had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction were approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and Enogex recorded an after tax gain of approximately $34.1 million during the second quarter of 2006. The proceeds from the sale, were used, among other things, to reduce short-term debt levels and fund capital expenditures.

As a result of this sale transaction, Gathering's sale of the Kinta Assets, which was part of the Natural Gas Pipeline segment, has been reported as discontinued operations for the three months ended March 31, 2007 and 2006 in the Condensed Consolidated Financial Statements. Results for these discontinued operations are summarized and discussed below.

	Three Months Ended March 31,	
(In millions)	**2007**	2006
Operating revenues	**$** ---	$ 6.6
Cost of goods sold	---	4.1
Gross margin on revenues	---	2.5
Other operation and maintenance	---	0.8
Depreciation	---	0.3
Taxes other than income	---	0.1
Operating income	---	1.3
Income tax expense	---	0.5
Net income	**$** ---	$ 0.8

Following the sale of the Kinta Assets in May 2006, no operations of the Kinta Assets are reflected in the Condensed Consolidated Financial Statements.

Financial Condition

The balance of Cash and Cash Equivalents was approximately $32.4 million and $47.9 million at March 31, 2007 and December 31, 2006, respectively, a decrease of approximately $15.5 million, or 32.4 percent, primarily due to bond interest payments, ad valorem tax payments and daily operational needs of the Company.

The balance of Accounts Receivable, Net was approximately $303.3 million and $344.3 million at March 31, 2007 and December 31, 2006, respectively, a decrease of approximately $41.0 million, or 11.9 percent, primarily due to lower natural gas sales prices and volumes by Enogex and a decrease in OG&E's billings to its customers reflecting milder weather in March 2007 as compared to December 2006.

The balance of current Price Risk Management assets was approximately $7.9 million and $41.9 million at March 31, 2007 and December 31, 2006, respectively, a decrease of approximately $34.0 million, or 81.1 percent. The decrease was primarily due to lower natural gas prices associated with OERI's short-term physical natural gas purchase transactions and associated financial contracts. A reduction in the volume of OERI's short-term physical natural gas activity and associated financial contracts outstanding at March 31, 2007 from December 31, 2006 also contributed to the decrease.

The balance of Construction Work in Progress was approximately $100.3 million and $191.1 million at March 31, 2007 and December 31, 2006, respectively, a decrease of approximately $90.8 million, or 47.5 percent, primarily due to OG&E's Centennial wind farm being placed in service during January 2007.

The balance of Accrued Taxes was approximately $26.8 million and $57.0 million at March 31, 2007 and December 31, 2006, respectively, a decrease of approximately $30.2 million, or 53.0 percent, primarily due to first quarter payments for ad valorem and federal income taxes.

The balance of Accrued Compensation was approximately $26.7 million and $46.0 million at March 31, 2007 and December 31, 2006, respectively, a decrease of approximately $19.3 million, or 42.0 percent, primarily due to the annual payment for incentive compensation made in the first quarter.

The balance of Fuel Clause Over Recoveries was approximately $126.3 million and $96.3 million at March 31, 2007 and December 31, 2006, respectively, an increase of approximately $30.0 million, or 31.2 percent, primarily due to the amount billed to OG&E's customers during 2007 exceeding OG&E's cost of fuel due to lower than expected natural gas prices. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E typically 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.

Off-Balance Sheet Arrangements

There have been no significant changes in the Company's off-balance sheet arrangements from those discussed in the Company's Form 10-K for the year ended December 31, 2006.

Liquidity and Capital Requirements

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and at Enogex. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage, delays in recovering unconditional fuel purchase obligations and fuel clause under and over recoveries. 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.

Future Capital Requirements

Capital Expenditures

The Company's current 2007 to 2012 construction program includes continued investment in OG&E's distribution, generation and transmission system and Enogex's pipeline assets. The Company's current estimates of capital expenditures for 2007 through 2012 are approximately $570.9 million, $753.5 million, $689.7 million, $563.7 million, $529.6 million and $492.1 million, respectively, which include capital expenditures of approximately $92.7 million, $278.8 million, $285.7 million, $97.7 million and $34.1 million, respectively, in 2007 through 2011 related to the construction of the Red Rock power plant.

Pension Plan Funding

The Company previously disclosed in its Form 10-K for the year ended December 31, 2006 that it may contribute up to $50 million to its pension plan during 2007. In April 2007, the Company contributed approximately $20 million to its pension plan and currently expects to contribute an additional $30 million to its pension plan during the remainder of 2007. Any expected contributions to the pension plan during 2007 are discretionary contributions, anticipated to be in the form of cash, and are not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

Adoption of FIN No. 48

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an amendment of FASB Statement No. 109," on January 1, 2007. As a result of the implementation of FIN No. 48, the Company recognized approximately a $3.8 million increase in the accrued interest liability, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings. The balance of uncertain tax positions at January 1, 2007 consisted of approximately $171.6 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility (see Note 6 of Notes to Consolidated Financial Statements for a further discussion).

Future Sources of Financing

Management expects that internally generated funds, the issuance of long and short-term debt and proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings will be adequate over the next three years to meet anticipated cash needs. 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.

Issuance of Long-Term Debt

OG&E expects to issue long-term debt during the third quarter of 2007 to fund capital expenditures for its Centennial wind farm.

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. In December 2006, the Company and OG&E increased their aggregate available borrowing capacity under their revolving credit agreements from $750.0 million to $1.0 billion, $600 million for the Company and $400 million for OG&E. Also, OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any time for a two-year period beginning January 1, 2007 and ending December 31, 2008. See Note 9 of Notes to Condensed Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

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, asset retirement obligations, fair value and cash flow hedges, regulatory assets and liabilities, unbilled revenues for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable and the valuation of energy purchase and sale contracts. The selection, application and disclosure of the Company's 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, 2006.

Accounting Pronouncements

See Notes 2 and 3 of Notes to Condensed Consolidated Financial Statements for a discussion of recent accounting pronouncements that are 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 retail restructuring efforts in Oklahoma and Arkansas have been postponed for the time being, if such efforts were renewed, retail competition and the unbundling of regulated energy service could have a significant financial impact on the Company due to an impairment of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. Any such restructuring also could have a significant impact on the Company's consolidated financial position, results of operations and cash flows. The Company cannot predict when it will be subject to changes in legislation or regulation, nor can it predict the impact of these changes on the Company's consolidated financial position, results of operations or cash flows. The Company believes that the prices for electricity and the quality and reliability of the Company's service currently place us in a position to compete effectively in the energy market. These developments at the state level are described in more detail in Note 13 of Notes to Condensed Consolidated Financial Statements. OG&E is also subject to competition in various degrees from state-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators. OG&E has a franchise to serve in more than 270 towns and cities throughout its service territory.

Commitments and Contingencies

Except as disclosed otherwise in this Form 10-Q, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of 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. See Notes 12 and 13 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q and Notes 17 and 18 of Notes to Consolidated Financial Statements and Item 3 of Part I of the Form 10-K for the year ended December 31, 2006 for a discussion of the Company's commitments and contingencies.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Except as set forth below, the market risks set forth in Part II, Item 7A of the Company's Form 10-K for the year ended December 31, 2006 appropriately represent, in all material respects, the market risks affecting the Company.

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.

Trading Activities

The trading activities are conducted throughout the year subject to daily and monthly trading stop loss limits set by the Risk Oversight Committee. Those trading stop loss limits currently are $2.5 million. The daily loss exposure from trading activities is measured primarily using value-at-risk ("VaR"), which estimates the potential losses the trading activities could incur over a specified time horizon and confidence level. The VaR limit defined and set by the Risk Oversight Committee for the Company's trading activities, assuming a 95 percent confidence level, currently is $1.5 million. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company's operating income.

A sensitivity analysis has been prepared to estimate the Company's exposure to market risk created by trading activities. 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. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in quoted market prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows for March 31, 2007.

(In millions)	Trading
Commodity market risk, net	$ 0.2

Non-Trading Activities

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 compensation received by the Company for operating some of its assets. To partially reduce non-trading commodity price risk, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the operating income of the Company. 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.

A sensitivity analysis has been prepared to estimate the Company's exposure to the market risk of the Company's 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. Quoted market prices are not available for all of the Company's non-trading positions, therefore, the value of non-trading positions is a summation of the forecasted values calculated for each commodity based upon internally generated forecast 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 result of this analysis, which may differ from actual results, is as follows for March 31, 2007.

(In millions)	Non-Trading
Commodity market risk, net	$ 10.9

The Company may designate certain derivative instruments for the purchase or sale of physical commodities, purchase or sale of electric power and fuel procurement as normal purchases and normal sales contracts under the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the Condensed Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. The Company applies normal purchases and normal sales to (i) commodity contracts for the purchase and sale of natural gas by its subsidiaries, Enogex Inc. and Gathering; (ii) commodity contracts for the sale of natural gas liquids produced by its subsidiary, Enogex Products Corporation; (iii) electric power contracts by OG&E; and (iv) fuel procurement by OG&E.

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 ("SEC") rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer ("CEO") and chief financial officer ("CFO"), allowing timely decisions regarding required disclosure. 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 CEO and CFO, of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the CEO and CFO have concluded that the Company's disclosure controls and procedures are effective.

No change in the Company's internal control over financial reporting has occurred during the Company's most recently completed fiscal quarter that has materially affected, or is 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).

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, 2006 for a description of certain legal proceedings presently pending. Except as set forth below and in Notes 12 and 13 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. United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E. (United States District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al. (United States District Court for the Eastern District of Louisiana, Case No. 97-2089; United States District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with Plaintiff's complaint, which is a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleges: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and British thermal unit content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees.

In qui tam actions, the United States Government can intervene and take over such actions from the relator. The Department of Justice, on behalf of the United States Government, decided not to intervene in this action.

The plaintiff filed over 70 other cases naming over 300 other defendants in various Federal Courts across the country containing nearly identical allegations. The Multidistrict Litigation Panel entered its order in late 1999 transferring and consolidating for pretrial purposes approximately 76 other similar actions filed in nine other Federal Courts. The consolidated cases are now before the United States District Court for the District of Wyoming.

In October 2002, the court granted the Department of Justice's motion to dismiss certain of the plaintiff's claims and issued an order dismissing the plaintiff's valuation claims against all defendants. Various procedural motions have been filed. A hearing on the defendants' motions to dismiss for lack of subject matter jurisdiction, including public disclosure, original source and voluntary disclosure requirements was held in 2005 and the special master ruled that OG&E and all Enogex parties named in these proceedings should be dismissed. This ruling was appealed to the District Court of Wyoming.

On October 20, 2006, the District Court of Wyoming ruled on Grynberg's appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex Services Corp., Transok, Inc. and OG&E, for lack of subject matter jurisdiction. Judgment was entered on November 17, 2006 and Grynberg filed his notice of appeal with the District Court of Wyoming. The defendants filed motions for attorneys' fees regarding issues of liability and Rule 11 motions on January 8, 2007. The defendants also filed for other legal costs on December 18, 2006. A hearing on these motions was held on April 24, 2007, at which time the judge in this matter took these motions under advisement. Grynberg has also filed appeals with the Tenth Circuit Court of Appeals. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Item 1A. Risk Factors.

There have been no significant changes in the Company's risk factors from those discussed in the Company's Form 10-K for the year ended December 31, 2006.

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
1/1/07 – 1/31/07	43,200	$ 38.55	N/A	N/A
2/1/07 – 2/28/07	---	$ ---	N/A	N/A
3/1/07 – 3/31/07	77,600	$ 37.77	N/A	N/A

N/A – not applicable

Item 6. Exhibits.

<u>Exhibit No.</u>	<u>Description</u>
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/ Scott Forbes
Scott Forbes
Controller – Chief Accounting Officer

May 2, 2007

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 have:

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

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

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

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

5. The registrant's other certifying officer 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: May 2, 2007

/s/ Steven E. Moore

Steven E. Moore
Chairman of the Board 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 have:

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

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

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

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

5. The registrant’s other certifying officer 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: May 2, 2007

/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 March 31, 2007, 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.

May 2, 2007

/s/ Steven E. Moore
Steven E. Moore
Chairman of the Board and
Chief Executive Officer

/s/ James R. Hatfield
James R. Hatfield
Senior Vice President and
Chief Financial Officer