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

FORM 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2005

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 _

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

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

As of September 30, 2005, 90,568,941 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2005

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Item 1. Financial Statements.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	**September 30, 2005**	December 31, 2004
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 27.5**	$ 23.1
Accounts receivable, less reserve of $4.2 and $4.5, respectively	**615.0**	484.5
Accrued unbilled revenues	**63.8**	45.5
Fuel inventories	**77.7**	89.0
Materials and supplies, at average cost	**56.3**	53.2
Price risk management	**678.7**	118.6
Gas imbalances	**90.2**	99.8
Accumulated deferred tax assets	**21.8**	13.7
Fuel clause under recoveries	**82.5**	54.3
Recoverable take or pay gas charges	**11.5**	17.0
Prepayments and other	**8.0**	13.3
Current assets of discontinued operations	**17.7**	7.2
Total current assets	**1,750.7**	1,019.2
OTHER PROPERTY AND INVESTMENTS, at cost	**32.8**	31.4
PROPERTY, PLANT AND EQUIPMENT		
In service	**5,988.2**	5,811.0
Construction work in progress	**89.7**	110.4
Other	**3.0**	1.1
Total property, plant and equipment	**6,080.9**	5,922.5
Less accumulated depreciation	**2,557.0**	2,474.1
Net property, plant and equipment	**3,523.9**	3,448.4
In service of discontinued operations	**146.5**	151.4
Less accumulated depreciation	**20.3**	18.8
Net property, plant and equipment of discontinued operations	**126.2**	132.6
Net property, plant and equipment	**3,650.1**	3,581.0
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**30.3**	30.9
Intangible asset - unamortized prior service cost	**38.0**	38.0
Prepaid benefit obligation	**98.9**	92.7
Price risk management	**51.8**	19.6
McClain Plant deferred expenses	**24.9**	11.0
Unamortized loss on reacquired debt	**20.1**	21.0
Unamortized debt issuance costs	**8.0**	8.7
Other	**11.3**	12.1
Deferred charges and other assets of discontinued operations	**4.9**	4.7
Total deferred charges and other assets	**288.2**	238.7
TOTAL ASSETS	**$ 5,721.8**	$ 4,870.3

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

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

(In millions)	**September 30, 2005**	December 31, 2004
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 238.5**	$ 125.0
Accounts payable	**499.2**	470.3
Dividends payable	**30.1**	29.9
Customers' deposits	**49.6**	48.3
Accrued taxes	**70.4**	13.2
Accrued interest	**26.7**	32.8
Tax collections payable	**11.3**	7.2
Accrued vacation	**18.7**	17.9
Long-term debt due within one year	**-**	34.3
Price risk management	**613.4**	102.9
Gas imbalances	**48.1**	22.4
Provision for payments of take or pay gas	**15.5**	21.0
Other	**40.1**	40.6
Current liabilities of discontinued operations	**11.8**	9.6
Total current liabilities	**1,673.4**	975.4
LONG-TERM DEBT		
Long-term debt	**1,354.0**	1,359.1
Long-term debt of discontinued operations	**64.0**	65.0
Total long-term debt	**1,418.0**	1,424.1
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**206.9**	197.0
Accumulated deferred income taxes	**822.6**	784.2
Accumulated deferred investment tax credits	**33.0**	36.8
Accrued removal obligations, net	**118.3**	122.2
Price risk management	**53.9**	6.6
Asset retirement obligation	**1.1**	1.1
Other	**14.8**	19.0
Deferred credits and other liabilities of discontinued operations	**20.1**	18.3
Total deferred credits and other liabilities	**1,270.7**	1,185.2
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**715.4**	700.8
Retained earnings	**724.6**	659.8
Accumulated other comprehensive loss, net of tax	**(80.3)**	(75.0)
Total stockholders' equity	**1,359.7**	1,285.6
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 5,721.8**	$ 4,870.3

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

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

(In millions, except per share data)	**Three Months Ended September 30, 2005**	Three Months Ended September 30, 2004	**Nine Months Ended September 30, 2005**	Nine Months Ended September 30, 2004
OPERATING REVENUES				
Electric Utility operating revenues	**$ 612.9**	$ 535.9	**$ 1,308.0**	$ 1,251.7
Natural Gas Pipeline operating revenues	**1,068.6**	783.3	**2,987.1**	2,254.9
Total operating revenues	**1,681.5**	1,319.2	**4,295.1**	3,506.6
COST OF GOODS SOLD				
Electric Utility cost of goods sold	**316.3**	267.3	**683.5**	669.6
Natural Gas Pipeline cost of goods sold	**1,016.7**	735.0	**2,839.3**	2,106.4
Total cost of goods sold	**1,333.0**	1,002.3	**3,522.8**	2,776.0
Gross margin on revenues	**348.5**	316.9	**772.3**	730.6
Other operation and maintenance	**93.8**	87.9	**292.3**	270.2
Depreciation	**47.4**	42.7	**137.5**	131.0
Impairment of assets	**-**	8.6	**-**	8.6
Taxes other than income	**17.2**	16.5	**52.4**	51.6
OPERATING INCOME	**190.1**	161.2	**290.1**	269.2
OTHER INCOME (EXPENSE)				
Other income	**0.7**	5.8	**3.3**	11.2
Other expense	**(2.0)**	(0.9)	**(4.7)**	(3.7)
Net other income (expense)	**(1.3)**	4.9	**(1.4)**	7.5
INTEREST INCOME (EXPENSE)				
Interest income	**0.3**	0.2	**2.4**	1.1
Interest on long-term debt	**(21.8)**	(17.2)	**(60.5)**	(51.8)
Interest expense – unconsolidated affiliate	**-**	(4.3)	**-**	(13.0)
Allowance for borrowed funds used during construction	**0.4**	0.9	**1.7**	1.2
Interest on short-term debt and other interest charges	**(5.3)**	(0.6)	**(8.6)**	(2.4)
Net interest expense	**(26.4)**	(21.0)	**(65.0)**	(64.9)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**162.4**	145.1	**223.7**	211.8
INCOME TAX EXPENSE	**55.3**	51.3	**75.8**	70.8
INCOME FROM CONTINUING OPERATIONS	**107.1**	93.8	**147.9**	141.0
DISCONTINUED OPERATIONS				
Income from discontinued operations	**5.9**	0.5	**10.7**	3.8
Income tax expense (benefit)	**1.9**	(0.3)	**3.7**	1.0
Income from discontinued operations	**4.0**	0.8	**7.0**	2.8
NET INCOME	**$ 111.1**	$ 94.6	**$ 154.9**	$ 143.8
BASIC AVERAGE COMMON SHARES OUTSTANDING	**90.4**	87.8	**90.2**	87.6
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**90.8**	88.3	**90.6**	88.1
BASIC EARNINGS PER AVERAGE COMMON SHARE				
Income from continuing operations	**$ 1.19**	$ 1.07	**$ 1.64**	$ 1.61
Income from discontinued operations, net of tax	**0.04**	0.01	**0.08**	0.03
NET INCOME	**$ 1.23**	$ 1.08	**$ 1.72**	$ 1.64
DILUTED EARNINGS PER AVERAGE COMMON SHARE				
Income from continuing operations	**$ 1.18**	$ 1.06	**$ 1.63**	$ 1.60
Income from discontinued operations, net of tax	**0.04**	0.01	**0.08**	0.03
NET INCOME	**$ 1.22**	$ 1.07	**$ 1.71**	$ 1.63
DIVIDENDS DECLARED PER SHARE	**$ 0.3325**	$ 0.3325	**$ 0.9975**	$ 0.9975

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

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

(In millions)	Nine Months Ended September 30, **2005**	2004
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income from continuing operations	**$ 147.9**	$ 141.0
Adjustments to reconcile net income to net cash provided from operating activities		
Depreciation	**137.5**	131.0
Impairment of assets	**-**	8.6
Deferred income taxes and investment tax credits, net	**31.0**	27.5
Gain on sale of assets	**(0.2)**	(6.3)
Price risk management assets	**(596.7)**	(95.8)
Price risk management liabilities	**551.7**	122.2
Other assets	**(15.0)**	(50.3)
Other liabilities	**(10.8)**	7.5
Change in certain current assets and liabilities		
Accounts receivable, net	**(130.5)**	(48.9)
Accrued unbilled revenues	**(18.3)**	(29.8)
Fuel, materials and supplies inventories	**8.2**	38.6
Gas imbalance asset	**9.6**	36.7
Fuel clause under recoveries	**(28.2)**	(44.9)
Other current assets	**8.9**	5.6
Accounts payable	**28.9**	32.3
Customers' deposits	**1.3**	4.5
Accrued taxes	**57.2**	56.2
Accrued interest	**(6.1)**	(6.8)
Fuel clause over recoveries	**-**	(32.4)
Gas imbalance liability	**25.7**	3.7
Other current liabilities	**0.8**	3.3
Net Cash Provided from Operating Activities	**202.9**	303.5
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	**(209.3)**	(356.9)
Proceeds from sale of assets	**1.4**	9.0
Other investing activities	**-**	0.7
Net Cash Used in Investing Activities	**(207.9)**	(347.2)
CASH FLOWS FROM FINANCING ACTIVITIES		
Retirement of long-term debt	**(34.3)**	(48.0)
Increase (decrease) in short-term debt, net	**113.5**	(192.3)
Proceeds from long-term debt	**-**	138.6
Premium on issuance of common stock	**14.6**	15.8
Dividends paid on common stock	**(89.9)**	(87.3)
Net Cash Provided from (Used in) Financing Activities	**3.9**	(173.2)
DISCONTINUED OPERATIONS		
Net cash used in operating activities	**(0.9)**	(10.6)
Net cash provided from (used in) investing activities	**7.0**	(0.3)
Net cash (used in) provided from financing activities	**(0.6)**	3.0
Net Cash Provided from (Used in) Discontinued Operations	**5.5**	(7.9)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**4.4**	(224.8)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**23.1**	231.0
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 27.5**	$ 6.2

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

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

1. Summary of Significant Accounting Policies

Organization

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

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

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries ("Enogex") and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership ("NOARK"), Enogex also owned a controlling interest in and operated Ozark Gas Transmission, L.L.C. ("OGT"), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. In September 2005, Enogex announced that it had entered into an agreement to sell its interest in Enogex Arkansas Pipeline Corporation ("EAPC"), which held the NOARK interest. This sale was completed on October 31, 2005. Also, during the third quarter of 2005, Enogex Compression Company, LLC ("Enogex Compression") sold it majority interest in Enerven Compression Services, LLC ("Enerven"), a joint venture focused on the rental of natural gas compression assets. These businesses have been reported as discontinued operations in the Company's Condensed Consolidated Financial Statements (see Note 4 for a further discussion).

The Company allocates operating costs to its affiliates based on several factors. Operating costs directly related to specific affiliates are assigned to those affiliates. Where more than one affiliate benefits from certain expenditures, the costs are shared between those affiliates receiving the benefits. Operating costs incurred for the benefit of all affiliates are allocated among the affiliates, based primarily upon head-count, occupancy, usage or the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, 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 September 30, 2005 and December 31, 2004, the results of its operations for the three and nine months ended September 30, 2005 and 2004, and the results of its cash flows for the nine months ended September 30, 2005 and 2004, have been included and are of a normal recurring nature.

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

Accounting Records

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

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

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

(In millions)	**September 30, 2005**	December 31, 2004
Regulatory Assets		
Fuel clause under recoveries	**$ 82.5**	$ 54.3
Income taxes recoverable from customers, net	**30.3**	30.9
McClain Plant expenses	**24.9**	11.0
Unamortized loss on reacquired debt	**20.1**	21.0
Recoverable take or pay gas charges	**11.5**	17.0
Cogeneration credit rider under recovery	**4.1**	-
Arkansas transition costs	-	0.7
January 2002 ice storm	-	1.8
Miscellaneous	**0.7**	0.6
Total Regulatory Assets	**$ 174.1**	$ 137.3
Regulatory Liabilities		
Accrued removal obligations, net	**$ 118.3**	$ 122.2
Total Regulatory Liabilities	**$ 118.3**	$ 122.2

In January 2005, a cogeneration credit rider was implemented at OG&E as part of the Oklahoma retail customer electric rates in order to return purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration previously included in base rates to OG&E's customers. This rider resulted in the seasonal over or under collection of revenues as the rider is based on an equal monthly amount of kilowatt-hour ("kwh") usage as compared to actual kwh usage. Due to the seasonal rates of OG&E's electric sales, this resulted in a temporary over collection of operating revenues in excess of the reduction in operating and maintenance expense for the first and second quarters of 2005 of approximately $5.9 million and a temporary under collection of operating revenues in excess of the reduction in operating and maintenance expense for the third quarter of 2005 of approximately $10.0 million (see "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – OG&E" for a further discussion). In August 2005, the Company determined that OG&E's net income should not be affected by over or under collections on a temporary or permanent basis, and accordingly, any difference should be deferred as a regulatory asset or liability. As a result, in order to better reflect the purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration from January 1, 2005 to September 30, 2005, OG&E recorded a regulatory asset of approximately $4.1 million in current assets as Prepayments and Other in the Condensed Consolidated Balance Sheet and a corresponding $4.1 million increase to Operating Revenues in the Condensed Consolidated Statement of Income. Going forward, OG&E expects any over or under collections related to the cogeneration credit rider to be reflected as a regulatory asset or liability.

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is reduced or written off, as appropriate. If the

Company were required to discontinue the application of SFAS No. 71 for some or all of its operations, it could result in writing off the related regulatory assets; the financial effects of which could be significant.

Income Taxes

The Company files consolidated income tax returns. Income taxes are allocated to each affiliate based on its separate taxable income or loss. Federal investment tax credits on electric utility property have been deferred and are being amortized to income over the life of the related property. Amortization of the federal investment tax credits was approximately $1.3 million for each of the three month periods ended September 30, 2005 and 2004 and was approximately $3.8 million and $3.9 million for the nine months ended September 30, 2005 and 2004, respectively, and are recorded as income tax benefits in the Condensed Consolidated Statements of Income.

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

OG&E has an Oklahoma investment tax credit ("ITC") carryover of approximately $6.8 million. These ITC carryover amounts will begin expiring in the year 2017. During 2005, additional investment tax credits of approximately $4.1 million are expected to be generated. OG&E believes that, based on current projections, the full $10.9 million of these ITC amounts will be fully utilized in 2006.

In June 2005, the Company filed amended Oklahoma and Arkansas state income tax returns for the years 1993 through 2003. The returns were filed to reflect changes resulting from Internal Revenue Service audit adjustments as well as additional Oklahoma investment tax credits for assets placed into service prior to 2001. During the third quarter of 2005, the Company received approximately $1.6 million of the $3.8 million of state income tax and Oklahoma investment tax credit refunds applied for. The Company expects to receive the remaining $2.2 million by the first quarter of 2006.

Stock-Based Compensation

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

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions, except per share data)	**2005**	2004	**2005**	2004
Net income, as reported	**$ 111.1**	$ 94.6	**$ 154.9**	$ 143.8
Add:				
Stock-based employee compensation expense included in reported net income, net of related tax effects	-	-	-	-
Deduct:				
Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	**0.1**	0.3	**0.4**	1.0
Pro forma net income	**$ 111.0**	$ 94.3	**$ 154.5**	$ 142.8
Income per average common share				
Basic – as reported	**$ 1.23**	$ 1.08	**$ 1.72**	$ 1.64
Diluted – as reported	**$ 1.22**	$ 1.07	**$ 1.71**	$ 1.63
Basic – pro forma	**$ 1.23**	$ 1.07	**$ 1.71**	$ 1.63
Diluted – pro forma	**$ 1.22**	$ 1.07	**$ 1.71**	$ 1.62

Reclassifications

Certain prior year amounts have been reclassified on the Condensed Consolidated Financial Statements to conform to the 2005 presentation.

2. Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123 (Revised), which replaces SFAS No. 123 and supersedes APB Opinion No. 25. This statement applies to all share-based payment transactions in which an entity acquires goods or services by issuing (or offering to issue) its shares, share options or other equity instruments (except for equity instruments held by an employee share ownership plan) or by incurring liabilities to an employee or other supplier (a) in amounts based, at least in part, on the price of the entity's shares or other equity instruments or (b) that require or may require settlement by issuing the entity's equity shares or other equity instruments. This statement applies to all awards granted after the required effective date and to awards modified, repurchased or cancelled after that date. The cumulative effect of initially applying this statement, if any, is recognized as of the required effective date. This statement requires a public entity to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with limited exceptions). The grant-date fair value of employee share options and similar instruments will be estimated using option-pricing models adjusted for the unique characteristics of those instruments. If an equity award is modified after the grant date, incremental compensation cost will be recognized in an amount equal to the excess of the fair value of the modified award over the fair value of the original award immediately before the modification. As of the required effective date, all public entities that used the fair-value based method for either recognition or disclosure under SFAS No. 123 will apply this statement using a modified version of prospective application. Under that transition method, compensation cost is recognized on or after the required effective date for the portion of outstanding awards for which the requisite service has not yet been rendered, based on the grant-date fair value of those awards calculated under SFAS No. 123 for either recognition or pro forma disclosures. Adoption of SFAS No. 123(R) is required for public entities as of the beginning of the first annual period beginning after June 15, 2005. The Company will adopt this new standard effective January 1, 2006. Management does not expect the impact of this new standard to have a material effect on its consolidated financial position or results of operations.

In March 2005, the FASB issued FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations," in which an entity is required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event if the liability's fair value can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred. Uncertainty surrounding the timing and method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. However, in some cases, there is insufficient information to estimate the fair value of an asset retirement obligation. In these cases, the liability should be initially recognized in the period in which sufficient information is available for an entity to make a reasonable estimate of the liability's fair value. This interpretation is effective no later than the end of fiscal years ending after December 15, 2005. The Company will adopt this new interpretation effective December 31, 2005. Retrospective application for interim financial information is permitted but not required. This interpretation will require both recognition of a cumulative change in accounting principle and disclosure of the liability on a pro forma basis for transition purposes. Management does not expect the impact of this new interpretation to have a material effect on its consolidated financial position or results of operations.

3. Accumulated Other Comprehensive Loss

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2005**	2004	**2005**	2004
Net income	**$ 111.1**	$ 94.6	**$ 154.9**	$ 143.8
Other comprehensive income (loss), net of tax:				
Deferred hedging losses, net of tax	**(5.4)**	(3.9)	**(5.5)**	(4.1)
Amortization of cash flow hedge, net of tax	**0.1**	-	**0.2**	-
Reversal of unrealized gains on available-for-sale securities	-	-	-	(0.4)
Total comprehensive income	**$ 105.8**	$ 90.7	**$ 149.6**	$ 139.3

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

(In millions)	**September 30, 2005**	December 31, 2004
Minimum pension liability adjustment, net of tax	**$ (72.7)**	$ (72.7)
Deferred hedging gains (losses), net of tax	**(5.3)**	0.2
Settlement and amortization of cash flow hedge, net of tax	**(2.3)**	(2.5)
Total accumulated other comprehensive loss	**$ (80.3)**	$ (75.0)

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

4. Enogex – Discontinued Operations

In April 2005, Enogex Compression received an unsolicited offer to buy its interest in Enerven, a joint venture focused on the rental of natural gas compression assets. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business. This business was part of the Natural Gas Pipeline segment.

Beginning in 2004, Enogex began evaluating the long term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on this evaluation, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in EAPC, which held the NOARK interest, for approximately $163 million plus an adjustment for working capital. The Company completed this sale transaction on October 31, 2005. The Company received approximately $173 million in cash proceeds, of which approximately $32 million will be applied to the repayment of long-term debt. The Company expects to recognize an after tax gain of slightly more than $50.0 million from the sale of this business in the fourth quarter. This business was part of the Natural Gas Pipeline segment.

The Consolidated Financial Statements of the Company have been restated to reflect Enogex Compression's sale of its Enerven interest and Enogex's sale of its EAPC interest, both of which were part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of Enerven and EAPC 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 September 30 is as follows:

CONDENSED CONSOLIDATED STATEMENTS OF INCOME DATA

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions)	**2005**	2004	**2005**	2004
Operating revenues from discontinued operations	**$ 22.1**	$ 17.5	**$ 58.3**	$ 54.0
Income from discontinued operations before taxes	**5.9**	0.5	**10.7**	3.8

CONDENSED CONSOLIDATED BALANCE SHEET DATA

(In millions)		**September 30, 2005**		December 31, 2004
Cash and cash equivalents	**$**	**14.5**	$	3.3
Accounts receivable, net		**3.0**		3.4
Other		**0.2**		0.5
Total current assets of discontinued operations	**$**	**17.7**	$	7.2
Plant in service of discontinued operations	**$**	**146.5**	$	151.4
Less accumulated depreciation		**20.3**		18.8
Net property, plant and equipment of discontinued operations	**$**	**126.2**	$	132.6
Total deferred charges and other assets of discontinued operations	**$**	**4.9**	$	4.7
Accounts payable	**$**	**6.4**	$	5.9
Accrued interest		**1.6**		0.4
Long-term debt due within one year		**2.0**		2.0
Other		**1.8**		1.3
Total current liabilities of discontinued operations	**$**	**11.8**	$	9.6
Total long-term debt of discontinued operations	**$**	**64.0**	$	65.0
Total deferred credits and other liabilities of discontinued operations	**$**	**20.1**	$	18.3

5. Supplemental Cash Flow Information

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

	Nine Months Ended September 30,			
(In millions)		**2005**		2004
NON-CASH INVESTING AND FINANCING ACTIVITIES				
Change in fair value of long-term debt due to interest rate swaps	**$**	**(4.3)**	$	(2.5)
Issuance of common stock		-		10.0

6. Common Stock

In July 2005, the Company filed a Form S-3 Registration Statement to register 7,000,000 shares of the Company's common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan ("DRIP/DSPP"). Under the terms of the DRIP/DSPP, the Company may accept requests for optional investments in amounts greater than $0.1 million per year and may offer a discount of up to three percent from current market prices. This program allows the Company to sell additional common stock at a smaller discount than that normally incurred in a secondary equity offering. During the nine months ended September 30, 2005, the Company did not issue any new shares of common stock pursuant to the DRIP/DSPP. During the nine months ended September 30, 2004, the Company issued 721,021 shares at a discount of 1.50 percent pursuant to the DRIP/DSPP. Also, as part of the DRIP/DSPP, the Company issued 49,662 shares of common stock at no discount during the nine months ended September 30, 2004.

For the three and nine months ended September 30, 2005, respectively, there were 268,536 and 605,502 shares of new common stock issued pursuant to the Company's Stock Incentive Plan, related to exercised stock options.

7. Earnings Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2005**	2004	**2005**	2004
Average Common Shares Outstanding				
Basic average common shares outstanding	**90.4**	87.8	**90.2**	87.6
Effect of dilutive securities:				
Employee stock options and unvested stock grants	**0.3**	0.2	**0.3**	0.2
Contingently issuable shares (performance units)	**0.1**	0.3	**0.1**	0.3
Diluted average common shares outstanding	**90.8**	88.3	**90.6**	88.1

For the three and nine months ended September 30, 2005, respectively, there were no shares and approximately 0.2 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 respective period. Approximately 0.7 million shares for each of the three and nine month periods ended September 30, 2004, related to outstanding employee stock options, were not included in the calculation of diluted earnings per average common share because the effect of including those shares is anti-dilutive as the exercise price of the stock options exceeded the average common stock market price during the respective period.

8. Long-Term Debt

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

Refinancing of Long-Term Debt

In August 2005, OG&E filed a Form S-3 Registration Statement to register the sale of up to $400.0 million of OG&E's unsecured debt securities. On October 15, 2005, OG&E paid at maturity its $110 million of 7.125 percent senior notes and redeemed its $110 million of 7.30 percent senior notes due October 15, 2025 at the principal amount plus a $3.6 million premium. The repayments were funded temporarily through the issuance of commercial paper by the Company and OG&E and borrowings under existing credit agreements which OG&E intends to replace through the issuance of long-term debt later in 2005.

Long-Term Debt with Optional Redemption Provisions

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

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

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

Interest Rate Swap Agreement

Fair Value Hedge

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

At September 30, 2005 and December 31, 2004, the fair values pursuant to OG&E’s interest rate swap were approximately $3.6 million and $3.9 million, respectively, and the fair value hedge was classified as Current Assets – Price Risk Management and Deferred Charges and Other Assets – Price Risk Management, respectively, in the Condensed Consolidated Balance Sheets. A corresponding net increase of approximately $3.6 million and $3.9 million was reflected in Long-Term Debt at September 30, 2005 and December 31, 2004 as this fair value hedge was effective at September 30, 2005 and December 31, 2004. On September 1, 2005, the counterparty to OG&E’s interest rate swap agreement exercised its right to change the termination date of the interest rate swap agreement from October 15, 2025 to October 15, 2005 in conjunction with the early redemption of long-term debt discussed above. On October 17, 2005, OG&E received approximately $5.3 million related to the termination of its interest rate agreement of which approximately $1.7 million is related to interest received and approximately $3.6 million is related to canceling the interest rate swap agreement, which will be amortized over the life of the long-term debt OG&E intends to issue later in 2005.

9. Short-Term Debt

The short-term debt balance was approximately $238.5 million and $125.0 million at September 30, 2005 and December 31, 2004, respectively. The following table shows the Company’s lines of credit in place, commercial paper outstanding and available cash at September 30, 2005. At September 30, 2005, the Company’s short-term borrowings consisted of commercial paper.

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

Entity	Amount Available	Amount Outstanding	Average Interest Rate	Maturity
OGE Energy Corp.	$ 15.0	$ -	N/A	April 6, 2006
OG&E (A)	150.0	-	N/A	September 30, 2010 (B)
OGE Energy Corp. (C)	600.0	238.5	3.875%	September 30, 2010 (B)
	765.0	238.5	N/A	
Cash	27.5	N/A	N/A	N/A
Total	$ 792.5	$ 238.5	3.875%	

(A) No borrowings were outstanding at September 30, 2005 under this line of credit; however, $0.2 million of this line of credit supports a letter of credit.
(B) On September 30, 2005, the Company and OG&E entered into revolving credit agreements totaling $750 million. These agreements include two separate facilities, one for the Company in an amount up to $600 million and one for OG&E in an amount up to $150 million. Each of the credit facilities has a five-year term with two options to extend the term for one year.
(C) This bank facility is available to back up a maximum of $300.0 million of the Company’s commercial paper borrowings and can be used as a letter of credit facility. At September 30, 2005, the Company had approximately $238.5 million in commercial paper borrowings.

The Company’s and OG&E’s ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Their respective back-up lines of credit contain pricing grids based on our credit ratings that cause annual fees and borrowing rates to increase if 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 $400 million in short-term borrowings at any one time for a two-year period beginning January 1, 2005 and ending December 31, 2006.

10. Retirement Plans and Postretirement Benefit Plans

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

Net Periodic Benefit Cost

	Pension Plan and Restoration of Retirement Income Plan			
	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions)	**2005**	2004	**2005**	2004
Service cost	**$ 4.8**	$ 4.3	**$ 14.3**	$ 12.7
Interest cost	**7.6**	7.4	**22.8**	22.2
Return on plan assets	**(8.5)**	(7.9)	**(25.6)**	(23.7)
Amortization of net loss	**3.6**	2.9	**11.0**	8.9
Amortization of unrecognized prior service cost	**1.6**	1.6	**4.7**	4.8
Net periodic benefit cost	**$ 9.1**	$ 8.3	**$ 27.2**	$ 24.9

	Postretirement Benefit Plans			
	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions)	**2005**	2004	**2005**	2004
Service cost	**$ 0.8**	$ 0.8	**$ 2.4**	$ 2.3
Interest cost	**2.6**	2.8	**7.8**	8.3
Return on plan assets	**(1.3)**	(1.4)	**(4.1)**	(4.2)
Amortization of transition obligation	**0.7**	0.6	**2.1**	2.0
Amortization of net loss	**1.2**	1.3	**3.8**	3.8
Amortization of unrecognized prior service cost	**0.5**	0.5	**1.5**	1.5
Net periodic benefit cost	**$ 4.5**	$ 4.6	**$ 13.5**	$ 13.7

Pension Plan Funding

The Company has contributed approximately $32.0 million in 2005 to its pension plan, which represents the Company's 2004 pension expense, of which approximately $10.7 million was contributed during the third quarter of 2005. The contributions to the pension plan in 2005, in the form of cash, were discretionary contributions and were 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 and nine months ended September 30, 2005 primarily includes unallocated corporate expenses, interest expense on commercial paper and interest expense on long-term debt. Other Operations for the three and nine months ended September 30, 2004 primarily includes unallocated corporate expenses, interest expense to unconsolidated affiliate and interest expense on commercial paper. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. The following tables summarize the results of the Company's business segments for the three and nine months ended September 30, 2005 and 2004.

Three Months Ended September 30, 2005	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 612.9**	**$ 1,115.7**	**$ -**	**$ (47.1)**	**$ 1,681.5**
Cost of goods sold	**328.3**	**1,051.7**	**-**	**(47.0)**	**1,333.0**
Gross margin on revenues	**284.6**	**64.0**	**-**	**(0.1)**	**348.5**
Other operation and maintenance	**73.0**	**23.4**	**(2.6)**	**-**	**93.8**
Depreciation	**34.7**	**10.7**	**2.0**	**-**	**47.4**
Taxes other than income	**12.9**	**3.7**	**0.6**	**-**	**17.2**
Operating income (loss)	**164.0**	**26.2**	**-**	**(0.1)**	**190.1**
Other income	**0.2**	**0.2**	**0.3**	**-**	**0.7**
Other expense	**(1.3)**	**-**	**(0.7)**	**-**	**(2.0)**
Interest income	**0.3**	**0.3**	**0.2**	**(0.5)**	**0.3**
Interest expense	**(15.1)**	**(8.3)**	**(3.8)**	**0.5**	**(26.7)**
Income tax expense (benefit)	**48.7**	**7.4**	**(0.7)**	**(0.1)**	**55.3**
Income (loss) from continuing operations	**99.4**	**11.0**	**(3.3)**	**-**	**107.1**
Income from discontinued operations	**-**	**4.0**	**-**	**-**	**4.0**
Net income (loss)	**$ 99.4**	**$ 15.0**	**$ (3.3)**	**$ -**	**$ 111.1**
Total assets	**$ 3,279.8**	**$ 2,375.0**	**$ 1,887.4**	**$ (1,820.4)**	**$ 5,721.8**

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

Three Months Ended September 30, 2005	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	**$ 68.7**	**$ 163.5**	**$ 1,021.6**	**$ (138.1)**	**$ 1,115.7**
Operating income (loss)	**$ 13.5**	**$ 21.2**	**$ (8.5)**	**$ -**	**$ 26.2**

Three Months Ended September 30, 2004	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 535.9	$ 811.2	$ -	$ (27.9)	$ 1,319.2
Cost of goods sold	280.9	749.3	-	(27.9)	1,002.3
Gross margin on revenues	255.0	61.9	-	-	316.9
Other operation and maintenance	65.7	24.3	(2.1)	-	87.9
Depreciation	30.2	10.9	1.6	-	42.7
Impairment of assets	-	8.6	-	-	8.6
Taxes other than income	11.7	4.1	0.7	-	16.5
Operating income (loss)	147.4	14.0	(0.2)	-	161.2
Other income	4.0	1.6	0.2	-	5.8
Other expense	(0.6)	(0.1)	(0.2)	-	(0.9)
Interest income	0.2	0.4	0.6	(1.0)	0.2
Interest expense	(8.9)	(8.1)	(5.2)	1.0	(21.2)
Income tax expense (benefit)	50.8	2.3	(1.8)	-	51.3
Income (loss) from continuing operations	91.3	5.5	(3.0)	-	93.8
Income from discontinued operations	-	0.8	-	-	0.8
Net income (loss)	$ 91.3	$ 6.3	$ (3.0)	$ -	$ 94.6
Total assets	$ 3,147.2	$ 1,708.7	$ 1,808.6	$ (1,878.5)	$ 4,786.0

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

Three Months Ended September 30, 2004	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 58.6	$ 144.1	$ 703.7	$ (95.2)	$ 811.2
Operating income (loss)	$ 7.0	$ 17.0	$ (10.0)	$ -	$ 14.0

Nine Months Ended September 30, 2005	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 1,308.0**	**$ 3,087.8**	**$ -**	**$ (100.7)**	**$ 4,295.1**
Cost of goods sold	**719.2**	**2,905.1**	**-**	**(101.5)**	**3,522.8**
Gross margin on revenues	**588.8**	**182.7**	**-**	**0.8**	**772.3**
Other operation and maintenance	**230.1**	**70.7**	**(8.5)**	**-**	**292.3**
Depreciation	**99.2**	**32.3**	**6.0**	**-**	**137.5**
Taxes other than income	**37.7**	**12.2**	**2.5**	**-**	**52.4**
Operating income	**221.8**	**67.5**	**-**	**0.8**	**290.1**
Other income	**1.2**	**0.7**	**1.4**	**-**	**3.3**
Other expense	**(2.1)**	**(0.1)**	**(2.5)**	**-**	**(4.7)**
Interest income	**1.9**	**1.4**	**0.7**	**(1.6)**	**2.4**
Interest expense	**(34.5)**	**(24.4)**	**(10.1)**	**1.6**	**(67.4)**
Income tax expense (benefit)	**60.9**	**17.8**	**(3.2)**	**0.3**	**75.8**
Income (loss) from continuing operations	**127.4**	**27.3**	**(7.3)**	**0.5**	**147.9**
Income from discontinued operations	**-**	**7.0**	**-**	**-**	**7.0**
Net income (loss)	**$ 127.4**	**$ 34.3**	**$ (7.3)**	**$ 0.5**	**$ 154.9**
Total assets	**$ 3,279.8**	**$ 2,375.0**	**$ 1,887.4**	**$ (1,820.4)**	**$ 5,721.8**

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

Nine Months Ended September 30, 2005	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	**$ 181.4**	**$ 477.6**	**$ 2,812.3**	**$ (383.5)**	**$ 3,087.8**
Operating income (loss)	**$ 31.7**	**$ 50.8**	**$ (15.0)**	**$ -**	**$ 67.5**

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

Nine Months Ended September 30, 2004	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 1,251.7	$ 2,326.2	$ -	$ (71.3)	$ 3,506.6
Cost of goods sold	707.0	2,140.3	-	(71.3)	2,776.0
Gross margin on revenues	544.7	185.9	-	-	730.6
Other operation and maintenance	208.7	70.8	(9.3)	-	270.2
Depreciation	92.4	31.9	6.7	-	131.0
Impairment of assets	-	8.6	-	-	8.6
Taxes other than income	36.2	12.8	2.6	-	51.6
Operating income	207.4	61.8	-	-	269.2
Other income	5.1	4.7	1.4	-	11.2
Other expense	(1.9)	(0.1)	(1.7)	-	(3.7)
Interest income	0.4	0.9	1.2	(1.4)	1.1
Interest expense	(28.2)	(24.8)	(14.4)	1.4	(66.0)
Income tax expense (benefit)	61.1	14.7	(5.0)	-	70.8
Income (loss) from continuing operations	121.7	27.8	(8.5)	-	141.0
Income from discontinued operations	-	2.8	-	-	2.8
Net income (loss)	$ 121.7	$ 30.6	$ (8.5)	$ -	$ 143.8
Total assets	$ 3,147.2	$ 1,708.7	$ 1,808.6	$ (1,878.5)	$ 4,786.0

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

Nine Months Ended September 30, 2004	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 193.0	$ 402.1	$ 2,058.8	$ (327.7)	$ 2,326.2
Operating income (loss)	$ 33.1	$ 39.5	$ (10.8)	$ -	$ 61.8

12. Commitments and Contingencies

Except as set forth below and in Note 13, the circumstances set forth in Note 17 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2004 appropriately represent, in all material respects, the current status of any material commitments and contingent liabilities.

Natural Gas Storage Facility Agreement with Central Oklahoma Oil and Gas Corp.

As reported in Note 17 to the Company's Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2004, OGE Energy Corp., Enogex, Central Oklahoma Oil and Gas Corp. ("COOG"), Natural Gas Storage Corporation ("NGSC") and individual shareholders of COOG and NGSC have been involved in legal proceedings relating to a gas storage agreement and associated agreements. In the actions pending against the individuals in the U.S. District Court for Western District of Oklahoma, the jury, on October 25, 2004, ruled in favor of the Company and Enogex for approximately $6.6 million. The individual defendants filed a motion for new trial. On March 23, 2005, the court entered an order: (i) denying the defendants' motion for new trial; (ii) denying the defendants' motion to stay; and (iii) granting the motion of OGE Energy Corp. and Enogex to allow registration of judgments in the U.S. District Court for the Southern District of Texas. On April 20, 2005, the defendants filed an appeal in the Tenth Circuit Court of Appeals. On September 14, 2005, the defendants posted a cash bond for approximately $6.9 million to stay the execution of the judgment pending appeal. The Company intends to continue to vigorously pursue its rights in conjunction with the remaining amounts owed under the judgments, plus interest. In a related action filed in Harris County, Texas in 2002 by NGSC and pending against the Company, on September 30, 2005 an order was entered by the Texas Court disposing of the entire Texas action based on a lack of jurisdiction.

Natural Gas Measurement Case

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

G.M. Oil Properties Litigation

On March 8, 2005, Enogex was served with a putative class action filed by G.M. Oil Properties, Inc. in the District Court of Comanche County, Oklahoma. The petition alleges that Enogex exercises a monopoly power with respect to its gathering facilities within the state of Oklahoma. The petition further alleges that, due to the alleged monopoly power, Enogex has caused damage to the plaintiff and other small gas producers and marketers. The Company intends to vigorously defend this action. At the present time, the Company believes the case is without merit and is filing a motion to dismiss for failure to state a claim.

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

OGE Energy Resources, Inc. ("OERI") and Cheyenne Plains Gas Pipeline Company, L.L.C. are parties to a firm transportation services agreement dated April 14, 2004. The Cheyenne Plains Pipeline provides interstate gas transportation services in Wyoming, Colorado and Kansas with a capacity of 560,000 decatherms/day ("Dth/day"). OERI reserved 60,000 Dth/day of firm capacity on the Cheyenne Plains Pipeline for 10 years. Such reservation provides OERI access to significant additional natural gas supplies in the Rocky Mountain production basins. OERI pays a demand fee of approximately $7.5 million annually for this capacity. If current market conditions continue, OERI could incur a loss up to approximately $3.7 million in 2005 related to its Cheyenne Plains' position as a result of unfavorable market conditions for the capacity primarily due to the earlier than expected in-service date for the project and the associated lack of upstream gas supply and pipeline infrastructure to deliver gas to the Cheyenne hub for 2005. OERI incurred a loss of approximately $0.3 million and $2.1 million during the three and nine months ended September 30, 2005, respectively, related to its Cheyenne Plains' position.

Pipeline Rupture

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

Railcar Lease Agreement

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

Environmental Laws and Regulations

OG&E

Air

On March 10, 2005, the Environmental Protection Agency ("EPA") published the Clean Air Interstate Rule ("CAIR"). This rule is intended to control sulfur dioxide ("SO2") and nitrogen oxide ("NOX") emissions from utility boilers in order to minimize the interstate transport of air pollution. The state of Oklahoma is not listed as one of the states affected by the rule. However, states not subject to the CAIR must demonstrate to the EPA that their emissions do not significantly impact the air quality in downwind states. If a state cannot make this demonstration it then becomes subject to the CAIR. If Oklahoma becomes subject to the CAIR, OG&E could have significant additional capital and operating expenditures.

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

Every five years, the EPA is required to review and revise, if necessary, each ambient air quality standard. The standard for particulate matter is currently under review. On July 1, 2005, the EPA announced that its staff scientists concluded that the current primary national ambient air quality standards for particulate matter for fine particles should be lowered and that the standard for coarse particles should be replaced with new standards. If this occurs, parts of Oklahoma could become "non-attainment" and reductions in emissions from OG&E's coal-fired boilers could be required which may result in significant capital and operating expenditures.

On June 15, 2005, the 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 Class I areas. If an impact from affected OG&E facilities is determined, OG&E must propose emission controls to meet ODEQ requirements. Federal requirements are currently being incorporated into the state implementation plan through rulemaking. The study and proposed reductions or controls, if needed, must be submitted to the ODEQ by December 2006. OG&E will have five years from the date of approval of a compliance plan to institute any required reductions. If an impact is determined and the regulations remain in effect, then significant capital and operating expenditures will be required for OG&E's Sooner, Muskogee, Seminole and Horseshoe Lake generating stations.

Water

OG&E has one Oklahoma Pollutant Discharge Elimination System permit renewal pending. OG&E expects that this permit will be issued during the fourth quarter of 2005. OG&E expects that this permit, when finally issued, will continue to be reasonable in its requirements, allow operational flexibility and provide reductions in operating costs.

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 316(b) rules for existing facilities became effective July 23, 2004. OG&E has engaged a consultant to assist in the development of the required documentation for four facilities. These documents are expected to be submitted to the state regulatory agency for review and approval during the fourth quarter of 2005. The Company has provided the state of Oklahoma with information and requests that, if approved by the state, may reduce the impact of the 316(b) rules on the Company because if the Company's position is approved, three of the four Company facilities would not be required to comply with the 316(b) rules.

Depending on the ultimate analysis and final determinations regarding the 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. Management consults with counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Except as otherwise stated above, in Note 13 below, in Item 1 of Part II of this Form 10-Q, in Notes 17 and 18 of Notes to Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2004 and in Item 3 of that report, management, after consultation with legal counsel, does not 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, 2004 appropriately represent, in all material respects, the current status of any regulatory matters.

Completed Regulatory Matters

2002 Settlement Agreement

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

Acquisition of Power Plant

On July 9, 2004, OG&E completed the acquisition of NRG McClain LLC's 77 percent interest in the 520 MW NRG McClain Station (the "McClain Plant"). This transaction was intended to satisfy the requirement in the Settlement Agreement to acquire New Generation. The McClain Plant, which includes natural gas-fired combined cycle combustion turbine units, is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority.

The closing of the purchase of the McClain Plant was subject to approval from the FERC. On July 2, 2004, the FERC authorized OG&E to acquire the McClain Plant. The FERC's approval was based on an offer of settlement in which OG&E proposed, among other things, to install certain new transmission facilities and to hire an independent market monitor to oversee OG&E's activity for a limited period. Two other parties, InterGen Services, Inc. and AES Shady Point ("AES"), opposed OG&E's offer of settlement and filed competing offers of settlement. In the July 2, 2004 order, the FERC: (i) approved OG&E's offer of settlement subject to conditions; (ii) rejected the competing offers of settlement; and (iii) approved OG&E's acquisition of the McClain Plant. As part of the July 2, 2004 order, OG&E agreed to undertake the following mitigation measures: (i) install a transformer at one of its facilities at a cost of approximately $9.3 million which was completed in the fourth quarter of 2004; (ii) provide a 600 MW bridge into its control area from the Redbud Energy LP ("Redbud") plant; and (iii) hire an independent market monitor to oversee OG&E's activity in its control area. On April 18, 2005, the FERC issued an order denying the party's request for rehearing. This party, who had 60 days to file a petition for review with the appropriate U.S. Court of Appeals, did not make a filing within this time period. OG&E completed the installation and implementation of the mitigation measures and notified the FERC in writing on May 31, 2005 that these were completed. OG&E's obligation to make available transmission capacity ("ATC") to the Redbud power plant by voluntary dispatch was also terminated upon implementation of the permanent mitigation measures. The market monitoring plan is designed to detect any anticompetitive conduct by OG&E from operation of its generation resources or its transmission system. The market monitoring function is performed daily and periodic reviews are also performed. To date, the independent market monitor has submitted five quarterly reports each covering the quarterly periods subsequent to the McClain Plant acquisition. Based on an analysis of transmission congestion data on OG&E's system, along with data on purchases and sales, generation dispatch data and power flows on OG&E's tie lines, the market monitor has concluded that OG&E has not acted in an anticompetitive manner through either dispatch of its generation or operation of its transmission system. Further, in the review of the disposition of requests for transmission service, the independent market monitor detected no problems with access to OG&E's transmission system. In August 2005, the market monitor initiated a special investigation into the circumstances surrounding the denial of firm transmission service by the Southwest Power Pool ("SPP") from Redbud to OG&E. In its third quarter 2005 report, the market monitor concluded that differences in the SPP modeling assumptions included an error in modeling made by the SPP, which was the primary cause for the denial of service. The market monitor further states that the ATC created by the mitigation upgrades matches the claims made by OG&E. One party filed a request for rehearing of the FERC's July 2, 2004 order. On September 21, 2005, the FERC asked OG&E and the SPP specific questions regarding the transmission upgrades outlined in the settlement offer as modified in the McClain Plant acquisition. In OG&E's response to the FERC data requests associated with this docket, OG&E replied that the transmission upgrades specified in the FERC's July 2, 2004 order approving OG&E's modified settlement offer had been completed. One party filed reply comments on October 24, 2005.

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

Enogex FERC Section 311 2001 Rate Case

Pursuant to a settlement accepted by the FERC in May 2003 to resolve Enogex's 2001 Section 311 rate case, Enogex assessed a fee under certain market conditions for processing customer gas gathered behind processing plants so that it met the heating value standards of natural gas transmission pipelines ("default processing fee"). Pursuant to Enogex's Statement of Operating Conditions ("SOC") that was effective through September 30, 2004, if Enogex's annual processing gross margin on revenues ("gross margin") exceeded a specified threshold, Enogex was required to record a default processing fee refund obligation in an amount equal to the lesser of the default processing fees or the amount of the processing margin in excess of the specified threshold. In June 2004, Enogex billed default processing fees of approximately $0.2 million, which was recorded as deferred revenue. Based on the processing gross margin for 2004, these default processing fees billed to customers were recorded as deferred revenue and were refunded or credited to customers by April 30, 2005.

Enogex FERC Section 311 2004 Rate Cases and related FERC dockets

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

The FERC Staff and various intervenors served data requests on Enogex concerning the revised SOC, the rate filing and the two fuel filings. Enogex responded to the discovery. Three technical conferences were held in four dockets on January 13, 2005, March 30, 2005 and June 7-8, 2005. On June 8, 2005, the parties reached a settlement in principle resolving all issues in all four dockets. On August 16, 2005, Enogex filed an uncontested offer of settlement that the FERC approved, without modification or condition, by order of September 19, 2005. The settlement established new maximum interruptible Section 311 zonal rates for an east zone and a west zone on the Enogex system, confirmed that Enogex could unbundle its gathering and transportation services and permitted the fuel percentages for the last quarter of 2004 and for fuel year 2005 to become effective, as filed. The FERC order concludes all four proceedings which resulted in no refunds being due. Enogex will make its next annual fuel filing by November 15, 2005. Also, the FERC requires all intrastate pipeline offering 311 service to file a rate case every three years, meaning Enogex must file its next rate case no later than October 1, 2007.

OGT Spin Down

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

Gas Transportation and Storage Agreement

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

On April 29, 2003, as required by the Settlement Agreement, OG&E filed an application with the OCC in which OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of OG&E's natural gas-fired generation facilities. OG&E will pay Enogex annual demand fees of approximately $46.8 million for the right to transport specified maximum daily quantities ("MDQ") and maximum hourly quantities ("MHQ") of gas at various minimum gas delivery pressures depending on the operational needs of the individual generating facility. In addition, OG&E supplies system fuel in-kind for its pro-rata share of actual fuel and lost and unaccounted for gas on the transportation system. To the extent OG&E transports gas in quantities in excess of the prescribed MDQs or MHQs, it pays an overrun service charge. During the three months ended September 30, 2005 and 2004, OG&E paid Enogex approximately $12.0 million and $13.6 million, respectively, for gas transportation and storage services. During the nine months ended September 30, 2005 and 2004, OG&E paid Enogex approximately $35.7 million and $37.7 million, respectively, for gas transportation and storage services.

Hearings in this case before an administrative law judge ("ALJ") occurred from September 16-22, 2004. On October 22, 2004, the ALJ overseeing the proceeding recommended approximately $41.9 million annual demand fee recovery with OG&E refunding to its customers any demand fees collected in excess of this amount. The ALJ's recommendation also would have allowed OG&E to recover the amounts that Enogex charges OG&E (and that OG&E pays in kind) for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. OG&E and other parties to the proceeding appealed the ALJ's recommendation on November 1, 2004 and a hearing in this case was held before the OCC on December 7, 2004. On July 14, 2005, the OCC issued an order in this case that, with one exception, approved the recovery recommended by the ALJ. The one exception was that the OCC order disallowed the recovery by OG&E of the amount that Enogex charges OG&E for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. Over the last three years, this amount has ranged from $1.6 million to $3.7 million annually. OG&E currently expects this amount to be between approximately $1.2 million and $1.6 million in 2005. The OCC's order will require OG&E to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC's order. Based on the order, OG&E's refund obligation was approximately $8.8 million. The balance of the refund obligation was approximately $8.1 million at September 30, 2005. OG&E began refunding this obligation in September 2005 through its automatic fuel adjustment clause. The OCC order was subject to appeal by any party to the proceeding. The time in which to appeal the OCC's order has expired and the OCC order was not appealed.

In addition to providing a refund to Oklahoma customers, OG&E has also recorded a refund obligation in Arkansas. OG&E expects to make a filing with the APSC to determine the amount of the refund. Based on information to date, OG&E expects to have a refund obligation of approximately $1.1 million at September 30, 2005 to Arkansas customers. The Arkansas refund obligation was calculated consistent with the Oklahoma calculation. OG&E expects to begin refunding this obligation sometime in 2006.

Security Enhancements

On April 8, 2002, OG&E filed a joint application with the OCC requesting approval for security investments and a rider to recover these costs from the ratepayers. On August 14, 2002, OG&E filed testimony with the OCC outlining proposed expenditures and related actions for security enhancement and a proposed recovery rider. The OCC Staff retained a security expert to review the report filed by OG&E. On July 13, 2004, the security expert filed testimony that recommended: (i) $19.0 million in capital expenditures and $2.5 million annually in operating and maintenance expenses are justified to enhance the security of OG&E's infrastructure; and (ii) a security rider should be authorized to recover costs as these projects are completed. On August 4, 2004, OG&E filed responsive testimony that quantified the minimal customer impact and revised its request for security investments so that it was consistent with the OCC Staff's recommendations. On August 13, 2004, the only intervening party, the Oklahoma Industrial Energy Consumers ("OIEC"), filed a statement of position which supported the OCC Staff's recommendations. 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 security rider. OG&E expects to implement the security rider by either the end of 2005 or early 2006.

Pending Regulatory Matters

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

OG&E Oklahoma Rate Case Filing

On May 20, 2005, OG&E filed with the OCC an application for an annual rate increase of approximately $89.1 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. The application also included, among other things, implementation of enhanced reliability programs in OG&E's system and increased fuel oil inventory, the establishment of a separate recovery mechanism for major storm expense, the establishment of new rate classes for public schools and related facilities, the establishment of a military base rider, the establishment of a new low income assistance tariff and the decision to make the guaranteed flat bill pilot tariff permanent for residential and small business customers. In the rate case filing, OG&E proposes that new rates go into effect upon issuance of an order by the OCC no later than 180 days from the date of filing of the application.

On September 12, 2005, several parties filed responsive testimony reflecting various positions on the issues related to this case. In particular, the testimony of the OCC Staff recommended that OG&E be entitled a rate increase of approximately $13.0 million, one-seventh the amount requested by OG&E in its May 20, 2005 application. The recommendations in the testimony of the Attorney General's office and the OIEC recommended a rate decrease of approximately $24 million and $31 million, respectively. Hearings in the rate case began on October 10, 2005 and concluded on October 24, 2005 with the proposed effective date of the rate change in December 2005. Late on November 3, 2005, the Referee appointed by the OCC for this proceeding issued a report recommending a rate increase for OG&E. Based on

OG&E's evaluation to date, OG&E estimates that the Referee's report recommends a rate increase of approximately $42 million. The Referee's recommendation is subject to review and possible change by the OCC. The Company currently expects the OCC to issue an order on OG&E's requested rate increase in November 2005.

As provided in the Settlement Agreement, until OG&E seeks and obtains approval of a request to increase base rates to recover, among other things, the investment in the McClain Plant, OG&E had the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the completion of the acquisition and the operation of the McClain Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. If the OCC were to approve OG&E's rate increase in the requested amount, all prudently incurred costs accrued through the regulatory asset within the 12-month period would be included in OG&E's prospective cost of service and would be recovered over a period to be determined by the OCC. OG&E's rate case application included an estimate of $25.9 million related to the McClain Plant regulatory asset. At September 30, 2005, the McClain Plant regulatory asset was approximately $24.9 million. OG&E completed its acquisition of the McClain Plant on July 9, 2004. Accordingly, OG&E ceased accruing various operating and related costs associated with the McClain Plant as a regulatory asset on July 8, 2005 and such costs are now being expensed in the Company's consolidated financial statements. OG&E estimates these amounts will be approximately $14.7 million for the six months ended December 31, 2005.

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

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

Competitive Bidding and Prudence Reviews for Electric Utility Providers

On March 10, 2005, the OCC filed Cause No. PUD 200500129 regarding "Inquiry of the Oklahoma Corporation Commission into Guidelines for Establishing Rules for Competitive Bidding and Prudence Reviews for Electric Utility Providers." As an electric utility provider, any such guidelines that were adopted would likely impact OG&E. Technical conferences were held in April 2005, and a hearing and deliberations were held in early June. On June 10, 2005, the OCC voted to close this notice of inquiry and directed the OCC Staff to open a rulemaking to address the competitive bidding issue for electric utilities. A technical conference was held on October 28, 2005. Comments are due November 17, 2005 and a hearing before the OCC is scheduled to begin December 8, 2005. At this time, OG&E cannot determine the impact that this rulemaking could have on its operations.

Power Purchase Agreement Filings

On February 4, 2005, Chermac Energy Corporation ("Chermac") and Sleeping Bear, LLC filed an application at the OCC (Cause No. PUD 200500059) seeking establishment of purchased power rates and a power purchase agreement with OG&E pursuant to the Public Utility Regulatory Policy Act of 1978 ("PURPA") for Chermac's proposed Buffalo/Sleeping Bear wind project. On September 15, 2005, the ALJ heard arguments on why the application should or should not be dismissed. On October 20, 2005, the ALJ suspended the current procedural schedule so that the parties involved in the proceeding can enter into negotiations. If a settlement is not reached prior to December 6, 2005, a new procedural schedule will be established with hearings expected to begin February 21, 2006.

On April 28, 2005, Chermac and Sleeping Bear, LLC filed a second application at the OCC (Cause No. PUD 200500177) seeking establishment of purchased power rates and a power purchase agreement with OG&E pursuant to PURPA for Chermac's proposed Sleeping Bear South wind project. On September 15, 2005, the ALJ heard arguments on why the application should or should not be dismissed. On October 20, 2005, the ALJ suspended the current procedural schedule so that the parties involved in the proceeding can enter into negotiations. If a settlement is not reached prior to December 6, 2005, a new procedural schedule will be established with hearings expected to begin February 21, 2006.

OG&E Arkansas Rate Case Filing

OG&E has determined that it will not file a rate case in the Arkansas jurisdiction during 2005. Beginning in January 2006, OG&E expects to analyze whether a rate case filing in Arkansas is justified. If warranted, a rate case could be filed sometime in 2006.

Southwest Power Pool

The regional state committee, which is comprised of commissioners of the applicable state regulatory commissions, finished its process of formulating a methodology for funding transmission expansion in the SPP control area by allocating costs of transmission expansion to the SPP members who benefit. The SPP Board of Directors adopted this plan and filed it with the FERC on February 28, 2005, Docket No. ER05-652. The FERC conditionally accepted the plan on April 21, 2005 with an effective date of May 5, 2005. The SPP made a second compliance filing on October 20, 2005 on various minor issues associated with the plan.

The SPP filed on June 15, 2005, Docket No. ER05-1118, to create a real-time, offer-based imbalance energy market which 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 filing contains provisions allowing the SPP to order certain dispatching of generating units and a market monitoring plan which 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. The scheduled implementation date of the imbalance energy market is May 1, 2006. On September 19, 2005, the FERC rejected the June 15, 2005 filing; however, the FERC provided guidance for the SPPs follow-up filing, which is anticipated to be made in the fourth quarter of 2005.

On August 8, 2005, the SPP filed with the FERC for approval, Docket No. ER05-1285, among other items, a standard definition of “transmission” to be used in the SPP regional transmission organization (“RTO”). The definition provides a uniform basis for application of formula rates, exercise of functional control of the transmission system, planning and expansion of the transmission system, compensation of new transmission owners and provides for a three-year period for petitioning for deviations from the bright line definition. The basic definition of transmission facilities is similar to definitions accepted for other RTOs. On September 30, 2005, the FERC accepted the definition, with minor modification.

Market-Based Rate Authority

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

On June 7, 2005, the FERC issued an order on OG&E’s and OERI’s market-based rate filing. Because OG&E and OERI failed the market share screen for OG&E’s control area, the FERC set OG&E’s and OERI’s market-based sales in OG&E’s control area for investigation pursuant to Section 206 of the Federal Power Act to investigate whether OG&E and OERI may continue to sell power at market-based rates in OG&E’s control area. The initiation of the investigation and imposition of the filing requirements do not constitute a finding that OG&E and OERI can exercise market power. OG&E and OERI have been requested to provide additional information that demonstrates to the FERC that they cannot exercise market power in the first-tier markets as well. However, the order conditionally allows OG&E and OERI to sell power in first-tier markets subject to OG&E and OERI providing additional information that clearly shows that they pass the market share screen for the first-tier markets. OG&E and OERI provided that additional information on July 7, 2005. 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 that are delivered to customers 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 are delivered to customers in OG&E's control area. OG&E and OERI also informed the FERC that any new agreements for long-term sales to loads that are delivered to customers in OG&E's control area will be filed with the FERC under Section 205 and not under market based rate tariffs. OG&E and OERI do not know when the FERC will conclude this investigation.

National Energy Legislation

In August 2005, Congress passed and the President signed into law a comprehensive energy bill, portions of which are of interest to the Company and to the industry. There are several provisions in the bill that have a positive impact on the Company. Provisions minimizing the risk of future uneconomic purchased power contracts forced on the Company under PURPA, tax incentives for investment in electric transmission and gas pipeline systems, mandatory reliability requirements by the North American Electric Reliability Council with oversight by the FERC and improved FERC siting authority for construction of electric transmission in disputed areas are included in the new law. Another significant provision for the utility industry is the repeal of the Public Utility Holding Company Act of 1935. This provision has minimal impact on the current operations of the Company.

State Legislative Initiatives

Oklahoma

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

Arkansas

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

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, 2004.

(In millions)	**September 30, 2005**		December 31, 2004	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 727.0**	**$ 727.0**	$ 130.3	$ 130.3
Interest Rate Swaps	**3.6**	**3.6**	7.9	7.9
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 667.4**	**$ 667.4**	$ 109.5	$ 109.5
Long-Term Debt				
Enogex Notes – continuing operations	**$ 407.9**	**$ 426.2**	$ 447.1	$ 482.1
Enogex Note – discontinued operations	**66.0**	**71.3**	67.0	71.0

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

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

Introduction

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

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

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries ("Enogex") and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership ("NOARK"), Enogex also owned a controlling interest in and operated Ozark Gas Transmission, L.L.C. ("OGT"), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. In September 2005, Enogex announced that it had entered into an agreement to sell its interest in Enogex Arkansas Pipeline Corporation ("EAPC"), which held the NOARK interest. This sale was completed on October 31, 2005. The Company expects to recognize an after tax gain slightly more than $50.0 million from the sale of this business in the fourth quarter. Enogex intends to use $32 million of the $173 million cash proceeds from the sale to repay long-term debt associated with EAPC. The balance of the proceeds will be used to invest, over time, in strategic assets to diversify its asset base. Also, during the third quarter of 2005, Enogex Compression Company, LLC ("Enogex Compression") sold it majority interest in Enerven Compression Services, LLC ("Enerven"), a joint venture focused on the rental of natural gas compression assets. These businesses have been reported as discontinued operations in the Company's Condensed Consolidated Financial Statements and are discussed further in Note 4 of Notes to Condensed Consolidated Financial Statements.

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in "Outlook", are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential", "project" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures; the Company's ability and the ability of its subsidiaries to obtain financing on favorable terms; prices of electricity, 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; federal or state legislation and regulatory decisions (including OG&E's pending rate case before the OCC) 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; creditworthiness of suppliers, customers and other contractual parties; the higher degree of risk associated with the Company's nonregulated business compared with the Company's regulated utility business; and other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission including Exhibit 99.01 to the Company's Form 10-K for the year ended December 31, 2004.

Overview

Summary of Operating Results

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

The Company reported net income of approximately $111.1 million, or $1.22 per diluted share, as compared to approximately $94.6 million, or $1.07 per diluted share, for the three months ended September 30, 2005 and 2004, respectively. The increase in net income for the three months ended September 30, 2005 as compared to the same period in 2004 was primarily due to:

- OG&E reporting net income of approximately $99.4 million, or $1.09 per diluted share of the Company's common stock, as compared to approximately $91.3 million, or $1.03 per diluted share, for the three months ended September 30, 2005 and 2004, respectively; and
- Enogex's operations, including discontinued operations, reporting net income of approximately $15.0 million, or $0.17 per diluted share of the Company's common stock, as compared to approximately $6.3 million, or $0.07 per diluted share, for the three months ended September 30, 2005 and 2004, respectively.

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

- a net loss at the holding company of approximately $3.3 million, or $0.04 per diluted share, for the three months ended September 30, 2005 as compared to a net loss of approximately $3.0 million, or $0.03 per diluted share, during the same period in 2004.

The slight change in results at the holding company reflects higher other expenses related to the Company's deferred compensation plan and restoration of retirement income plan and a lower income tax benefit partially offset by lower net interest expense of approximately $1.1 million.

Nine months ended September 30, 2005 as compared to nine months ended September 30, 2004

The Company reported net income of approximately $154.9 million, or $1.71 per diluted share, as compared to approximately $143.8 million, or $1.63 per diluted share, for the nine months ended September 30, 2005 and 2004, respectively. The increase in net income for the nine months ended September 30, 2005 as compared to the same period in 2004 was primarily due to:

- OG&E reporting net income of approximately $127.4 million, or $1.41 per diluted share of the Company's common stock, as compared to approximately $121.7 million, or $1.38 per diluted share, for the nine months ended September 30, 2005 and 2004, respectively;
- Enogex's operations, including discontinued operations, reporting net income of approximately $34.3 million, or $0.38 per diluted share of the Company's common stock, as compared to approximately $30.6 million, or $0.35 per diluted share, for the nine months ended September 30, 2005 and 2004, respectively; and
- a net loss at the holding company of approximately $6.8 million, or $0.08 per diluted share, for the nine months ended September 30, 2005 as compared to a net loss of approximately $8.5 million, or $0.10 per diluted share, during the same period in 2004 reflecting lower net interest expense of approximately $4.0 million partially offset by a lower income tax benefit.

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

Regulatory Matters

As part of the settlement of OG&E's rate case in November 2002 (the "Settlement Agreement"), OG&E agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. Although the prescribed bidding process detailed in the Settlement Agreement provided that separate transportation services be bid for each generation facility, OG&E believed that, in order for it to achieve maximum coal generation, to deliver the lowest cost energy to its customers and to ensure reliable electric service, it must have integrated, firm no-notice load following service for both gas transportation and gas storage. Because the required integrated service was not available in the marketplace from parties other than Enogex, on April 29, 2003, OG&E filed an application with the OCC in which OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of OG&E's natural gas-fired generation facilities. OG&E will pay Enogex annual demand fees of approximately $46.8 million for the right to transport specified maximum daily quantities ("MDQ") and maximum hourly quantities ("MHQ") of gas at various minimum gas delivery pressures depending on the operational needs of the individual generating facility. In addition, OG&E supplies system fuel in-kind for its pro-rata share of actual fuel and lost and unaccounted for gas on the transportation system. To the extent OG&E transports gas in quantities in excess of the prescribed MDQs or MHQs, it pays an overrun service charge. During the three months ended September 30, 2005 and 2004, OG&E paid Enogex approximately $12.0 million and $13.6 million, respectively, for gas transportation and storage services. During the nine months ended September 30, 2005 and 2004, OG&E paid Enogex approximately $35.7 million and $37.7 million, respectively, for gas transportation and storage services.

On July 14, 2005, the OCC issued an order in this case that, with one exception, approved the recovery recommended by the administrative law judge overseeing the proceeding. The one exception was that the OCC order disallowed the recovery by OG&E of the amount that Enogex charges OG&E for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. Over the last three years, this amount has ranged from $1.6 million to $3.7 million annually. OG&E currently expects this amount to be between approximately $1.2 million and $1.6 million in 2005. The OCC's order will require OG&E to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC's order. Based on the order, OG&E's refund obligation was approximately $8.8 million. The balance of the refund obligation was approximately $8.1 million at September 30, 2005. OG&E began refunding this obligation in September 2005 through its automatic fuel adjustment clause.

In addition to providing a refund to Oklahoma customers, OG&E has also recorded a refund obligation in Arkansas. OG&E expects to make a filing with the APSC to determine the amount of the refund. Based on information to date, OG&E expects to have a refund obligation of approximately $1.1 million at September 30, 2005 to Arkansas customers. The Arkansas refund obligation was calculated consistent with the Oklahoma calculation. OG&E expects to begin refunding this obligation sometime in 2006. For further information, see Note 13 of Notes to Condensed Consolidated Financial Statements.

On May 20, 2005, OG&E filed with the OCC an application for an annual rate increase of approximately $89.1 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. The application also included, among other things, implementation of enhanced reliability programs in OG&E's system and increased fuel oil inventory, the establishment of a separate recovery mechanism for major storm expense, the establishment of new rate classes for public schools and related facilities, the establishment of a military base rider, the establishment of a new low income assistance tariff and the decision to make the guaranteed flat bill pilot tariff permanent for residential and small business customers. In the rate case filing, OG&E proposes that new rates go into effect upon issuance of an order by the OCC no later than 180 days from the date of filing of the application.

On September 12, 2005, several parties filed responsive testimony reflecting various positions on the issues related to this case. In particular, the testimony of the OCC Staff recommended that OG&E be entitled a rate increase of approximately $13.0 million, one-seventh the amount requested by OG&E in its May 20, 2005 application. The recommendations in the testimony of the Attorney General's office and the Oklahoma Industrial Energy Consumers recommended a rate decrease of approximately $24 million and $31 million, respectively. Hearings in the rate case began on October 10, 2005 and concluded on October 24, 2005 with the proposed effective date of the rate change in December 2005. Late on November 3, 2005, the Referee appointed by the OCC for this proceeding issued a report recommending a rate increase for OG&E. Based on OG&E's evaluation to date, OG&E estimates that the Referee's report recommends a rate increase of approximately $42 million. The Referee's recommendation is subject to review and possible change by the OCC. The Company currently expects the OCC to issue an order on OG&E's requested rate increase in November 2005. For further information regarding this rate case, see Note 13 of Notes to Condensed Consolidated Financial Statements.

Coal Shipment Disruption

In July 2005, OG&E received notification from Union Pacific Railroad ("Union Pacific") that, in May 2005, Union Pacific and BNSF Railway ("BNSF") experienced successive derailments on the jointly-owned rail line serving the Southern Powder River Basin coal producers. According to Union Pacific, these two derailments were caused by track that had become unstable from an accumulation of coal dust in the roadbed combined with unusually heavy rainfall. BNSF, which maintains and operates the line, concluded that a significant part of the line must be repaired before normal train operations can resume. While the repairs are underway, Union Pacific will be unable to operate at full capacity from the Powder River Basin. In September 2005, Union Pacific provided an update of the status of the repairs which indicated that the repairs are proceeding as scheduled and should be substantially completed by the end of November. Union Pacific expects repairs to resume in early 2006 and be completed in mid-2006. Union Pacific estimated that it will only be able to supply between 80 and 85 percent of the current coal demand needs during the months of July to November until the line is restored to full capacity. As a result, OG&E's burnable coal inventory has declined somewhat and could continue to decline through November. Additional derailments and weather-related track outages in October have resulted in further declines in coal inventories. As a result, OG&E has reduced its daily coal-fired generation and has increased production at its natural gas-fired generating units.

Potential New Enogex Project

Enogex recently announced that it had entered into a letter of intent with El Paso Corporation that is designed to accelerate El Paso's Continental Connector Project. The letter of intent contemplates arrangements by which El Paso or an affiliate would execute an initial lease of up to 750,000 decatherms per day ("Dth/day") of capacity on the Enogex pipeline system, with an option to expand up to 1.5 million Dth/day, so that the leased Enogex pipeline capacity would become an integral part of the Continental Connector Project. The letter of intent also contemplates a commitment by Enogex to secure up to 500,000 Dth/day of capacity subscriptions for the project. These arrangements would significantly reduce the amount of new mainline construction required for the project, resulting in less environmental disturbance and an earlier in-service target date of winter 2007-2008.

Under the letter of intent, the Continental Connector Project will use existing or expanded El Paso pipeline systems to transport capacity-constrained natural gas from Rocky Mountain and Mid-Continent supply regions to Custer, Oklahoma. At Custer, this gas and local Mid-Continent production will be transported on existing and expanded Enogex systems for Continental Connector under a long-term lease arrangement for re-delivery in the vicinity of Bennington, Oklahoma. From there, gas will be transported on new pipeline facilities through the Perryville, Louisiana, Hub to a termination with Tennessee and Southern Natural Pipelines at Pugh, Mississippi.

Enogex intends to work with El Paso to determine whether to advance this project. However, the commitments and obligations under the letter of intent are subject to various conditions, including definitive documentation and boards of directors' and regulatory approvals and there can be no assurance that the conditions will be satisfied. Pending satisfaction of these conditions, Enogex does not expect to incur material expenditures.

Outlook

The Company's 2005 earnings guidance is between $149 million to $158 million of net income, or $1.65 to $1.75 per diluted share, assuming approximately 91.0 million average diluted shares outstanding and excluding gains on asset sales of EAPC and Enerven (see "Enogex - Discontinued Operations" for a further discussion) of approximately $52 million, or $0.57 per diluted share. Including these gains, earnings per share for 2005 would be between $2.22 and $2.32. The Company believes that excluding the gain on the sale of assets from its earnings guidance is more representative of the Company's operating performance. The 2005 outlook for Enogex remains unchanged at $49 million to $56 million, or $0.54 to $0.62 per diluted share, with commodity spread projections between $2.30 and $2.60 per Million British thermal unit ("MMBtu") in 2005 and average natural gas liquids price projections between $1.00 and $1.10 per gallon in 2005. See "Outlook" in the Company's Form 10-K for the year ended December 31, 2004 and the Company's Form 10-Q for the quarter ended March 31, 2005 for a description of the underlying assumptions related to the earnings guidance for Enogex. The 2005 outlook now includes earnings guidance of $112 million to $116 million, or $1.23 to $1.27 per diluted share, at OG&E, up from $106 million to $110 million, or $1.17 to $1.22 per diluted share, primarily due to warmer than normal weather in September 2005. The 2005 outlook now includes earnings guidance at the holding company with a loss between $8 million and $10 million, or $0.09 to $0.11 per diluted share, which loss was increased from $6 million and $8 million, or $0.07 to $0.09 per diluted share, primarily due to higher forecasted interest expense in 2005. See "Outlook" in the Company's Form 10-K for the year ended December 31, 2004 for a description of other underlying assumptions related to the earnings guidance for OG&E and the holding company.

Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. As indicated above, the magnitude and timing of any potential impairment or gain on the disposition of any assets, including the gains on the sale of EAPC and Enerven, have not been included in the 2005 earnings guidance.

Results of Operations

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

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions, except per share data)	**2005**	2004	**2005**	2004
Operating income	**$ 190.1**	$ 161.2	**$ 290.1**	$ 269.2
Net income	**$ 111.1**	$ 94.6	**$ 154.9**	$ 143.8
Basic average common shares outstanding	**90.4**	87.8	**90.2**	87.6
Diluted average common shares outstanding	**90.8**	88.3	**90.6**	88.1
Basic earnings per average common share	**$ 1.23**	$ 1.08	**$ 1.72**	$ 1.64
Diluted earnings per average common share	**$ 1.22**	$ 1.07	**$ 1.71**	$ 1.63
Dividends declared per share	**$ 0.3325**	$ 0.3325	**$ 0.9975**	$ 0.9975

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

Operating Income (Loss) by Business Segment

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions)	**2005**	2004	**2005**	2004
OG&E (Electric Utility)	**$ 164.0**	$ 147.4	**$ 221.8**	$ 207.4
Enogex (Natural Gas Pipeline)	**26.2**	14.0	**67.5**	61.8
Other Operations (A)	**(0.1)**	(0.2)	**0.8**	-
Consolidated operating income	**$ 190.1**	$ 161.2	**$ 290.1**	$ 269.2

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

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

OG&E

(Dollars in millions)	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Operating revenues	**$ 612.9**	$ 535.9	**$ 1,308.0**	$ 1,251.7
Cost of goods sold	**328.3**	280.9	**719.2**	707.0
Gross margin on revenues	**284.6**	255.0	**588.8**	544.7
Other operation and maintenance	**73.0**	65.7	**230.1**	208.7
Depreciation	**34.7**	30.2	**99.2**	92.4
Taxes other than income	**12.9**	11.7	**37.7**	36.2
Operating income	**$ 164.0**	$ 147.4	**$ 221.8**	$ 207.4
Operating revenues by classification				
Residential	**$ 261.4**	$ 218.7	**$ 525.6**	$ 495.3
Commercial	**148.4**	134.2	**320.0**	309.7
Industrial	**110.7**	100.4	**258.6**	254.0
Public authorities	**57.9**	53.3	**127.5**	124.4
Sales for resale	**21.4**	17.9	**48.2**	44.3
Provision for refund on gas transportation and storage case	**-**	-	**(2.1)**	(6.4)
Other	**10.5**	11.2	**26.3**	29.9
System sales revenues	**610.3**	535.7	**1,304.1**	1,251.2
Off-system sales revenues	**2.6**	0.2	**3.9**	0.5
Total operating revenues	**$ 612.9**	$ 535.9	**$ 1,308.0**	$ 1,251.7
MWH (A) sales by classification (in millions)				
Residential	**3.0**	2.6	**6.8**	6.3
Commercial	**1.8**	1.7	**4.6**	4.4
Industrial	**1.9**	1.8	**5.4**	5.2
Public authorities	**0.8**	0.7	**2.1**	2.0
Sales for resale	**0.4**	0.4	**1.1**	1.1
System sales	**7.9**	7.2	**20.0**	19.0
Off-system sales	**-**	-	**-**	-
Total sales	**7.9**	7.2	**20.0**	19.0
Number of customers	**743,811**	733,243	**743,811**	733,243
Average cost of energy per KWH (B) - cents				
Fuel	**3.635**	3.244	**3.036**	2.891
Fuel and purchased power	**3.884**	3.635	**3.363**	3.462
Degree days (C)				
Heating				
Actual	**3**	-	**1,870**	1,962
Normal	**30**	29	**2,229**	2,247
Cooling				
Actual	**1,390**	1,120	**2,035**	1,760
Normal	**1,295**	1,295	**1,850**	1,850

(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 September 30, 2005 as compared to quarter ended September 30, 2004

OG&E’s operating income for the three months ended September 30, 2005 increased approximately $16.6 million or 11.3 percent as compared to the same period in 2004. The increase in operating income was primarily attributable to higher gross margin on revenues (“gross margin”) partially offset by higher operating expenses.

Gross margin, which is operating revenues less cost of goods sold, was approximately $284.6 million for the three months ended September 30, 2005 as compared to approximately $255.0 million during the same period in 2004, an increase of approximately $29.6 million or 11.6 percent. The gross margin increased primarily due to:

- warmer weather in OG&E's service territory, which increased the gross margin by approximately $24.8 million; and
- growth in OG&E's service territory primarily due to customer growth and increased usage, which increased the gross margin by approximately $10.7 million.

These increases in gross margin were partially offset by the seasonal under collection of revenues related to the cogeneration credit rider, implemented January 1, 2005, which reduced the gross margin by approximately $10.0 million as the rider is based on an equal monthly amount of kwh usage as compared to actual kwh usage partially offset by approximately a $4.1 million increase in operating revenues related to the temporary over collection and under collection of operating revenues from January 1, 2005 to September 30, 2005 (see Note 1 of Notes to Condensed Consolidated Financial Statements).

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $274.3 million for the three months ended September 30, 2005 as compared to approximately $220.1 million during the same period in 2004, an increase of approximately $54.2 million or 24.6 percent. The increase was primarily due to increased generation and a higher average cost of fuel per kwh. Purchased power costs were approximately $54.0 million for the three months ended September 30, 2005 as compared to approximately $60.8 million during the same period in 2004, a decrease of approximately $6.8 million or 11.2 percent. The decrease was primarily due to OG&E's ability to generate power at costs lower than third party costs, OG&E's completion of the acquisition of a 77 percent interest in the 520 megawatt ("MW") NRG McClain Station (the "McClain Plant") in 2004, the termination of a power purchase contract in August 2004 which was replaced with a new contract in September 2004 and the scheduled decrease in cogeneration capacity payments for another power purchase contract, which became effective in January 2005.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through automatic fuel adjustment clauses. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex. See Note 13 of Notes to Condensed Consolidated Financial Statements for a discussion of recently completed proceedings at the OCC regarding OG&E's gas transportation and storage contract with Enogex and a review of OG&E's automatic fuel adjustment clause for 2003.

Other operating and maintenance expenses were approximately $73.0 million for the three months ended September 30, 2005 as compared to approximately $65.7 million during the same period in 2004, an increase of approximately $7.3 million or 11.1 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries and wages expense of approximately $4.2 million, higher pension and benefit expense of approximately $1.2 million and higher employee expenses of approximately $0.3 million, primarily due to increased salary and wage rates; and
- higher materials and supplies expense of approximately $1.5 million and higher outside services expense of approximately $1.3 million, primarily due to higher expenses for infrastructure projects in the third quarter of 2005 as spending on infrastructure projects in the third quarter of 2004 was postponed as OG&E awaited an OCC order regarding whether OG&E had to reduce its rates, effective January 1, 2004.

These increases in other operating and maintenance expenses were partially offset by lower allocations from the holding company of approximately $1.4 million primarily due to lower miscellaneous corporate expenses.

Depreciation expense was approximately $34.7 million for the three months ended September 30, 2005 as compared to approximately $30.2 million during the same period in 2004, an increase of approximately $4.5 million or 14.9 percent, primarily due to a higher level of depreciable plant in addition to depreciation expense associated with the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.

Nine months ended September 30, 2005 as compared to nine months ended September 30, 2004

OG&E's operating income for the nine months ended September 30, 2005 increased approximately $14.4 million or 6.9 percent as compared to the same period in 2004. The increase in operating income was primarily attributable to higher gross margins partially offset by higher operating expenses.

Gross margin was approximately $588.8 million for the nine months ended September 30, 2005 as compared to approximately $544.7 million during the same period in 2004, an increase of approximately $44.1 million or 8.1 percent. The gross margin increased primarily due to:

- warmer weather in OG&E's service territory, which increased the gross margin by approximately $28.7 million; and
- growth in OG&E's service territory primarily due to customer growth and increased usage, which increased the gross margin by approximately $19.1 million.

These increases in gross margin were partially offset by the provision for refund associated with OG&E's gas transportation and storage case, which reduced the gross margin by approximately $2.0 million.

Fuel expense was approximately $578.2 million for the nine months ended September 30, 2005 as compared to approximately $490.6 million during the same period in 2004, an increase of approximately $87.6 million or 17.9 percent. The increase was primarily due to increased generation and a higher average cost of fuel per kwh. Purchased power costs were approximately $141.0 million for the nine months ended September 30, 2005 as compared to approximately $216.4 million during the same period in 2004, a decrease of approximately $75.4 million or 34.8 percent. The decrease was primarily due to OG&E's completion of the acquisition of the McClain Plant in 2004, the termination of a power purchase contract in August 2004 which was replaced with a new contract in September 2004 and the scheduled decrease in cogeneration capacity payments for another power purchase contract, which became effective in January 2005.

Other operating and maintenance expenses were approximately $230.1 million for the nine months ended September 30, 2005 as compared to approximately $208.7 million during the same period in 2004, an increase of approximately $21.4 million or 10.3 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries and wages expense of approximately $9.8 million, higher pension and benefit expense of approximately $2.8 million and higher employee expenses of approximately $1.3 million, primarily due to increased salary and wage rates; and
- higher outside services expense of approximately $6.9 million and higher materials and supplies expense of approximately $3.9 million, primarily due to higher expenses for infrastructure projects in the first nine months of 2005 as spending on infrastructure projects in the first nine months of 2004 was postponed as OG&E awaited an OCC order regarding whether OG&E had to reduce its rates, effective January 1, 2004.

These increases in other operating and maintenance expenses were partially offset by lower allocations from the holding company of approximately $4.8 million primarily due to lower miscellaneous corporate expenses.

Depreciation expense was approximately $99.2 million for the nine months ended September 30, 2005 as compared to approximately $92.4 million during the same period in 2004, an increase of approximately $6.8 million or 7.4 percent, primarily due to a higher level of depreciable plant in addition to depreciation expense associated with the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.

Enogex – Continuing Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Dollars in millions)	**2005**	2004	**2005**	2004
Operating revenues	**$ 1,115.7**	$ 811.2	**$ 3,087.8**	$ 2,326.2
Cost of goods sold	**1,051.7**	749.3	**2,905.1**	2,140.3
Gross margin on revenues	**64.0**	61.9	**182.7**	185.9
Other operation and maintenance	**23.4**	24.3	**70.7**	70.8
Depreciation	**10.7**	10.9	**32.3**	31.9
Impairment of assets	**-**	8.6	**-**	8.6
Taxes other than income	**3.7**	4.1	**12.2**	12.8
Operating income	**$ 26.2**	$ 14.0	**$ 67.5**	$ 61.8
New well connects	**71**	78	**193**	186
Gathered volumes – TBtu/d (A)	**1.01**	0.99	**1.00**	0.98
Incremental transportation volumes – TBtu/d	**0.52**	0.42	**0.43**	0.38
Total throughput volumes – TBtu/d	**1.53**	1.41	**1.43**	1.36
Natural gas processed – Mmcf/d (B)	**513**	498	**525**	494
Natural gas liquids sold (keep-whole) – million gallons	**63**	73	**225**	176
Natural gas liquids sold (POL and fixed-fee) – million gallons	**4**	4	**11**	12
Total natural gas liquids sold – million gallons	**67**	77	**236**	188
Average sales price per gallon	**$ 0.972**	$ 0.727	**$ 0.812**	$ 0.693

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

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

Enogex's operating income from continuing operations for the three months ended September 30, 2005 increased approximately $12.2 million or 87.1 percent as compared to the same period in 2004. The increase in operating income was attributable to, among other things, increased gross margins of approximately $4.8 million in Enogex's gathering and processing business, which was partially offset by decreased gross margins of approximately $2.3 million in Enogex's transportation and storage business and approximately $0.4 million in Enogex's marketing business. Also contributing to the increased operating income was an asset impairment charge of approximately $8.6 million recorded in the third quarter 2004.

Transportation and storage contributed approximately $27.4 million of Enogex's gross margin for the three months ended September 30, 2005 as compared to approximately $29.7 million during the same period in 2004, a decrease of approximately $2.3 million or 7.7 percent. The gross margin decreased primarily due to:

- reduced fuel recoveries due to timing related to fuel recoveries, which reduced the gross margin by approximately $3.2 million; and
- reduced demand fees due to fewer overrun charges in 2005, which reduced the gross margin by approximately $1.7 million.

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

- increased crosshaul prices and volumes, which increased the gross margin by approximately $1.7 million; and
- increased commodity revenues, which increased the gross margin by approximately $0.7 million due to favorable contract negotiations.

Gathering and processing contributed approximately $43.5 million of Enogex's gross margin for the three months ended September 30, 2005 as compared to approximately $38.7 million during the same period in 2004, an increase of approximately $4.8 million or 12.4 percent. Gathering gross margins increased approximately $5.0 million or 22.7 percent for the three months ended September 30, 2005 as compared to the same period in 2004. The gathering gross margin increased primarily due to:

- increased retained fuel volumes coupled with higher natural gas prices, which increased the gross margin by approximately $2.7 million; and

- contractual fuel gains primarily due to higher natural gas prices and renegotiated contracts, which increased the gross margin by approximately $2.0 million.

Processing gross margins decreased approximately $0.2 million or 1.2 percent for the three months ended September 30, 2005 as compared to the same period in 2004 primarily due to decreased commodity margins primarily due to reduced keep-whole volumes, which reduced the gross margin by approximately $0.9 million.

This decrease in the processing gross margin was partially offset by increased condensate margins primarily due to higher condensate prices, which increased the gross margin by approximately $0.7 million.

Marketing reduced Enogex's gross margin by approximately $6.9 million for the three months ended September 30, 2005 as compared to a reduction of approximately $6.5 million during the same period in 2004, a decrease of approximately $0.4 million or 6.2 percent. The gross margin decreased primarily due to:

- timing losses on transportation hedges compared to physical deliveries, which reduced the gross margin by approximately $3.2 million; and
- losses incurred related to Enogex's position on the Cheyenne Plains' transportation agreement, which reduced the gross margin by approximately $0.3 million.

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

- the timing of recognition of losses on storage hedges compared to physical sales and reduced storage demand fees, which increased the gross margin by approximately $2.3 million; and
- more favorable market conditions in the third quarter of 2005 as compared to the same period in 2004, which increased the gross margin by approximately $0.8 million.

Enogex's other operating and maintenance expenses were approximately $23.4 million for the three months ended September 30, 2005 as compared to approximately $24.3 million during the same period in 2004, a decrease of approximately $0.9 million or 3.7 percent. The decrease in other operating and maintenance expenses was primarily due to:

- an uncollectible debt reserve of approximately $0.8 million recorded in 2004 with no similar reserve recorded in 2005; and
- a decrease in outside services of approximately $0.7 million due to repairs at the Company's processing plants in 2004 with no similar repairs in 2005.

These decreases in other operating and maintenance expenses were partially offset by an increase in the allocations from the holding company of approximately $0.4 million.

Impairment of assets was approximately $8.6 million ($5.1 million after tax) for the three months ended September 30, 2004 as a result of recording an impairment charge during the third quarter of 2004 related to certain Enogex natural gas pipeline assets in which Enogex received notification from a customer that a transportation agreement involving four of Enogex's non-contiguous pipeline asset segments located in west Texas and used to serve the customer's power plants would be terminated effective December 31, 2004. There were no impairments recorded during the three months ended September 30, 2005.

During the three months ended September 30, 2005, Enogex had an increase in net income of approximately $4.0 million attributable to income from discontinued operations which the Company does not consider to be reflective of the ongoing profitability of Enogex's business. During the three months ended September 30, 2004, Enogex had a reduction to net income of approximately $1.4 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business. These items include an impairment charge of approximately $5.1 million which was partially offset by:

- authorized recovery of previously under recovered fuel of approximately $1.2 million;
- income tax adjustments of approximately $1.1 million;
- income from discontinued operations of approximately $0.8 million;
- a settlement related to a customer bankruptcy of approximately $0.5 million; and
- a gain on the sale of certain Enogex compression and processing assets of approximately $0.1 million.

Nine months ended September 30, 2005 as compared to nine months ended September 30, 2004

Enogex's operating income from continuing operations for the nine months ended September 30, 2005 increased approximately $5.7 million or 9.2 percent as compared to the same period in 2004. The increase in operating income was primarily attributable to an asset impairment charge of approximately $8.6 million recorded in the nine months ended September 30, 2004 as the gross margin decreased by approximately $3.2 million in 2005. Gross margins increased approximately $13.5 million in Enogex's gathering and processing business, which was more than offset by decreased gross margins of approximately $8.5 million in Enogex's marketing business and approximately $8.2 million in Enogex's transportation and storage business.

Transportation and storage contributed approximately $75.5 million of Enogex's gross margin for the nine months ended September 30, 2005 as compared to approximately $83.7 million during the same period in 2004, a decrease of approximately $8.2 million or 9.8 percent. The gross margin decreased primarily due to:

- reduced fuel recoveries due to timing related to fuel recoveries, which reduced the gross margin by approximately $13.1 million; and
- reduced demand fees due to fewer overrun charges and the loss of firm contracts, which reduced the gross margin by approximately $2.0 million.

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

- increased crosshaul prices and volumes, which increased the gross margin by approximately $4.5 million; and
- increased commodity and interruptible revenues, which increased the gross margin by approximately $1.8 million.

Gathering and processing contributed approximately $116.2 million of Enogex's gross margin for the nine months ended September 30, 2005 as compared to approximately $102.7 million during the same period in 2004, an increase of approximately $13.5 million or 13.1 percent. Gathering gross margins increased approximately $6.9 million or 10.6 percent for the nine months ended September 30, 2005 as compared to the same period in 2004. The gathering gross margin increased primarily due to:

- contractual fuel gains primarily due to higher natural gas prices and renegotiated contracts, which increased the gross margin by approximately $4.3 million;
- increased fuel over recoveries due to higher natural gas prices, which increased the gross margin by approximately $2.8 million; and
- higher volumes on the low pressure gathering systems, which increased the gross margin by approximately $1.4 million.

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

- lower margins on natural gas sales, which reduced the gross margin by approximately $1.3 million; and
- lower volumes on the high pressure gathering systems, which reduced the gross margin by approximately $0.6 million.

Processing gross margins increased approximately $6.6 million or 17.4 percent for the nine months ended September 30, 2005 as compared to the same period in 2004 primarily due to:

- increased keep-whole and percent of liquids margins primarily due to higher commodity spreads, which increased the gross margin by approximately $4.9 million; and
- increased condensate margins primarily due to higher condensate prices, which increased the gross margin by approximately $3.0 million.

These increases in the processing gross margin were partially offset by a reserve for a gross margin sharing contract, which reduced the gross margin by approximately $1.1 million.

Marketing reduced Enogex's gross margin by approximately $9.0 million for the nine months ended September 30, 2005 as compared to a reduction of approximately $0.5 million during the same period in 2004, a decrease of approximately $8.5 million. The gross margin decreased primarily due to:

- a correction to the accounting procedure for park and loan transactions (natural gas storage transactions) in 2004, which reduced the gross margin by approximately $7.7 million (see Note 11 of Notes to Condensed Consolidated Financial Statements);
- losses incurred related to Enogex's position on the Cheyenne Plains' transportation agreement, which reduced the gross margin by approximately $2.1 million; and
- timing losses on transportation hedges compared to physical deliveries, which reduced the gross margin by approximately $2.8 million.

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

- gains in storage activity, which increased the gross margin by approximately $2.7 million; and
- lower demand fees paid for storage services due to establishing new rates for the new storage season, which began April 1, 2004 which increased the gross margin by approximately $1.7 million.

Enogex's other operating and maintenance expenses were approximately $70.7 million for the nine months ended September 30, 2005 as compared to approximately $70.8 million during the same period in 2004, a decrease of approximately $0.1 million or 0.1 percent. The decrease in other operating and maintenance expenses was primarily due to an uncollectible debt reserve of approximately $1.0 million recorded in 2004 with no similar reserve recorded in 2005.

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

- expenses related to a pipeline rupture in the second quarter of 2005 of approximately $0.5 million; and
- an increase in insurance premiums for property insurance of approximately $0.3 million.

During the nine months ended September 30, 2005, Enogex had an increase in net income of approximately $2.3 million relating to income from discontinued operations of approximately $7.0 million partially offset by a correction to the accounting procedure for park and loan transactions in 2004 of approximately $4.7 million. During the nine months ended September 30, 2004, Enogex had an increase in net income of approximately $7.2 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business. The increase includes:

- income from discontinued operations of approximately $2.8 million;
- authorized recovery of previously under recovered fuel of approximately $2.5 million;
- Oklahoma investment tax credits of approximately $2.0 million;
- a gain on the sale of certain Enogex compression and processing assets of approximately $1.9 million;
- an imbalance settlement with a customer of approximately $1.5 million;
- income tax adjustments of approximately $1.1 million; and
- a settlement related to a customer bankruptcy of approximately $0.5 million.

These increases to net income were partially offset by an impairment charge of approximately $5.1 million.

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

Other income includes, among other things, contract work performed by OG&E, non-operating rental income, gain on the sale of assets, minority interest income and miscellaneous non-operating income. Other income was approximately $0.7 million for the three months ended September 30, 2005 as compared to approximately $5.8 million during the same period in 2004, a decrease of approximately $5.1 million or 87.9 percent. The decrease in other income was primarily due to gains in the three months ended September 30, 2004 of approximately $3.0 million from the sale of OG&E's interests in its natural gas producing properties, approximately $0.6 million from the repurchase of outstanding heat pump loans by OG&E and approximately $0.2 million from the sale of certain of Enogex's compression and processing assets. Also contributing to the decrease in other income was approximately $0.8 million received related to a bankruptcy from one of Enogex's customers during the third quarter of 2004 and an increase for OG&E of approximately $0.5 million due to the allowance for other funds used during construction during the third quarter of 2005.

Other income was approximately $3.3 million for the nine months ended September 30, 2005 as compared to approximately $11.2 million during the same period in 2004, a decrease of approximately $7.9 million or 70.5 percent. The decrease in other income was primarily due to gains in the nine months ended September 30, 2004 of approximately $3.0 million from the sale of OG&E's interests in its natural gas producing properties, approximately $3.0 million from the sale of certain of Enogex's compression and processing assets, approximately $0.6 million from the repurchase of outstanding heat pump loans by OG&E and approximately $0.3 million from the sale of land by OG&E near the Company's principal executive offices. Also contributing to the decrease in other income was approximately $0.8 million received related to a bankruptcy settlement from one of Enogex's customers during the third quarter of 2004 and an increase for OG&E of approximately $0.6 million due to the allowance for other funds used during construction during the nine months ended September 30, 2005.

Other expense includes, among other things, expenses from the losses on the sale of assets, minority interest expense, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions. Other expense was approximately $2.0 million for the three months ended September 30, 2005 as compared to approximately $0.9 million during the same period in 2004, an increase of approximately $1.1 million. The increase in other expense was primarily due to an increase in the liability associated with the deferred compensation plan and the restoration of retirement income plan of approximately $0.6 million, an increase of approximately $0.4 million in charitable contributions and an increase of approximately $0.2 million related to the termination of Mutual Business Program No. 19 ("MBP 19") in 2005.

Other expense was approximately $4.7 million for the nine months ended September 30, 2005 as compared to approximately $3.7 million during the same period in 2004, an increase of approximately $1.0 million or 27.0 percent. The increase in other expense was primarily due to an increase in the liability associated with the deferred compensation plan and the restoration of retirement income plan of approximately $0.5 million, an increase of approximately $0.2 million related to the termination of MBP 19 in 2005 and an increase of approximately $0.1 million in charitable contributions.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $26.4 million for the three months ended September 30, 2005 as compared to approximately $21.0 million during the same period in 2004, an increase of approximately $5.4 million or 25.7 percent. The increase in net interest expense was primarily due to:

- an increase in interest expense of approximately $2.5 million for additional interest expense related to income taxes as a result of new guidelines issued by the Internal Revenue Service related to a change in the method of accounting used to capitalize costs for self-construction for income tax purposes only;
- an increase in interest expense of approximately $2.2 million due to an increase in variable interest rates associated with the Company's interest rate swap agreements and variable rate industrial authority bonds;
- an increase in interest expense of approximately $2.1 million due to interest on debt associated with the McClain Plant acquisition, which OG&E ceased recording as a regulatory asset on July 8, 2005;
- an increase in interest expense of approximately $1.8 million due to higher commercial paper fees as a result of higher commercial paper outstanding; and
- an increase in interest expense of approximately $0.5 million due to a decrease in the allowance for borrowed funds used during construction.

These increases in net interest expense were partially offset by a net reduction in interest expense of approximately $4.0 million due to the reduction of long-term debt outstanding and refinancing certain long-term debt at a lower interest rate.

Net interest expense was approximately $65.0 million for the nine months ended September 30, 2005 as compared to approximately $64.9 million during the same period in 2004, an increase of approximately $0.1 million or 0.2 percent. The increase in net interest expense was primarily due to:

- an increase in interest expense of approximately $9.3 million due to an increase in variable interest rates associated with the Company's interest rate swap agreements and variable rate industrial authority bonds;
- an increase in interest expense of approximately $3.6 million due to higher commercial paper fees as a result of higher commercial paper outstanding;
- an increase in interest expense of approximately $2.5 million for additional interest expense related to income taxes as discussed above; and
- an increase in interest expense of approximately $2.1 million due to interest on debt associated with the McClain Plant acquisition, which OG&E ceased recording as a regulatory asset on July 8, 2005.

These increases in net interest expense were partially offset by:

- a net reduction in interest expense of approximately $15.6 million due to the reduction of long-term debt outstanding and refinancing certain long-term debt at a lower interest rate;
- an increase in interest income of approximately $1.4 million due to the interest portion of an income tax refund related to prior periods; and
- a reduction in interest expense of approximately $0.5 million due to an increase in the allowance for borrowed funds used during construction.

Income tax expense was approximately $55.3 million for the three months ended September 30, 2005 as compared to approximately $51.3 million during the same period in 2004, an increase of approximately $4.0 million or 7.8 percent. The increase in income tax expense was primarily due to:

- higher pre-tax income for the Company; and
- an increase in other permanent differences between book and tax net income.

These increases in income tax expense were partially offset by an increase in Oklahoma state tax credits of approximately $3.5 million during the three months ended September 30, 2005 as compared to the same period in 2004.

Income tax expense was approximately $75.8 million for the nine months ended September 30, 2005 as compared to approximately $70.8 million during the same period in 2004, an increase of approximately $5.0 million or 7.1 percent. The increase in income tax expense was primarily due to:

- higher pre-tax income for the Company; and
- a decrease in Oklahoma state tax credits of approximately $1.1 million during the nine months ended September 30, 2005 as compared to the same period in 2004.

These increases in income tax expense were partially offset by a decrease in other permanent differences between book and tax net income.

Enogex – Discontinued Operations

In April 2005, Enogex Compression received an unsolicited offer to buy its interest in Enerven, a joint venture focused on the rental of natural gas compression assets. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business. This business was part of the Natural Gas Pipeline segment.

Beginning in 2004, Enogex began evaluating the long term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on this evaluation, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in EAPC, which held the NOARK interest, for approximately $163 million plus an adjustment for working capital. The Company completed this sale transaction on October 31, 2005. The Company received approximately $173 million in cash proceeds, of which approximately $32 million will be applied to the repayment of long-term debt. The Company expects to recognize an after tax gain of slightly more than $50.0 million from the sale of this business in the fourth quarter. This business was part of the Natural Gas Pipeline segment.

As a result of these sale transactions, Enogex Compression's interest in Enerven and Enogex's interest in EAPC, which were part of the Natural Gas Pipeline segment, have been reported as discontinued operations for the three and nine months ended September 30, 2005 and 2004 in the Condensed Consolidated Financial Statements. Results for the discontinued operations are summarized and discussed below.

(In millions)	Three Months Ended September 30, 2005	2004	Nine Months Ended September 30, 2005	2004
Operating revenues	**$ 22.1**	$ 17.5	**$ 58.3**	$ 54.0
Cost of goods sold	**16.7**	13.9	**40.9**	39.8
Gross margin on revenues	**5.4**	3.6	**17.4**	14.2
Other operation and maintenance	**1.1**	1.1	**3.3**	3.0
Depreciation	**0.6**	0.8	**2.3**	2.7
Taxes other than income	**0.3**	0.3	**0.9**	0.8
Operating income	**3.4**	1.4	**10.9**	7.7
Other income	**3.3**	-	**3.3**	-
Other expense	**(0.3)**	(0.2)	**0.1**	0.1
Net interest expense	**1.1**	1.1	**3.4**	3.8
Income tax expense (benefit)	**1.9**	(0.3)	**3.7**	1.0
Net income	**$ 4.0**	$ 0.8	**$ 7.0**	$ 2.8

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

Gross margin increased approximately $1.8 million or 50.0 percent during the three months ended September 30, 2005 as compared to the same period in 2004 primarily due to increased fuel recoveries due to timing related to fuel recoveries.

Other operating expenses decreased approximately $0.2 million or 9.1 percent during the three months ended September 30, 2005 as compared to the same period in 2004 primarily due to ceasing depreciation expense in September 2005 when EAPC was reported as a discontinued operation.

Other income increased approximately $3.3 million during the three months ended September 30, 2005 as compared to the same period in 2004 primarily due to a gain of approximately $2.9 million recognized in the third quarter of 2005 related to the sale of Enogex Compression’s interest in Enerven.

Nine months ended September 30, 2005 as compared to nine months ended September 30, 2004

Gross margin increased approximately $3.2 million or 22.5 percent during the nine months ended September 30, 2005 as compared to the same period in 2004. The increase was primarily due to increased fuel recoveries due to timing related to fuel recoveries, which increased the gross margin by approximately $3.9 million.

This increase was partially offset by an overpayment of natural gas purchases in a prior period that was recognized during the nine months ended September 30, 2004 with no similar item recorded in 2005, which reduced the gross margin by approximately $0.5 million.

Other operating expenses were approximately $6.5 million for each of the nine month periods ended September 30, 2005 and 2004. Other operating expenses were affected by lower depreciation expense due to ceasing depreciation expense in September 2005 when EAPC was reported as a discontinued operation offset by higher operating and maintenance expenses.

Other income increased approximately $3.3 million during the nine months ended September 30, 2005 as compared to the same period in 2004 primarily due to a gain of approximately $2.9 million recognized in the third quarter of 2005 related to the sale of Enogex Compression’s interest in Enerven.

Financial Condition

The balance of Accounts Receivable was approximately $615.0 million and $484.5 million at September 30, 2005 and December 31, 2004, respectively, an increase of approximately $130.5 million or 26.9 percent. The increase was primarily due to an increase in OG&E’s billings to its customers reflecting warmer weather and increased pass through of fuel costs resulting from significantly higher natural gas costs in September 2005 as compared to December 2004 and an increase in natural gas sales activity by Enogex in the third quarter of 2005.

The balance of Accrued Unbilled Revenues was approximately $63.8 million and $45.5 million at September 30, 2005 and December 31, 2004, respectively, an increase of approximately $18.3 million or 40.2 percent. The increase reflects higher seasonal electric rates and increased usage due to warmer weather and increased pass through of fuel costs resulting from significantly higher fuel costs in September 2005 as compared to December 2004.

The balance of Fuel Inventories was approximately $77.7 million and $89.0 million at September 30, 2005 and December 31, 2004, respectively, a decrease of approximately $11.3 million or 12.7 percent. The decrease is primarily due to a decrease in coal inventories resulting from decreased coal deliveries from the Powder River Basin due to ongoing railroad repairs as described in "Overview – Regulatory Matters".

The balance of current Price Risk Management assets was approximately $678.7 million and $118.6 million at September 30, 2005 and December 31, 2004, respectively, an increase of approximately $560.1 million. The increase was primarily due to higher natural gas prices associated with the natural timing of existing park and loan transactions (natural gas storage transactions), related financial contracts associated with OGE Energy Resources, Inc.'s ("OERI") activities during the first nine months of 2005 and significantly higher natural gas futures. Approximately $84.8 million of the Company's natural gas storage transactions expired in October.

The balance of Fuel Clause Under Recoveries was approximately $82.5 million and $54.3 million at September 30, 2005 and December 31, 2004, respectively, an increase of approximately $28.2 million or 51.9 percent. The increase in fuel clause under recoveries was due to OG&E's cost of fuel exceeding the amount billed to OG&E's customers during the nine months ended September 30, 2005. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel cost in periods of rising prices above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under or over recovery. In September 2005, OG&E increased its Oklahoma fuel adjustment factor from 0.0112500 to 0.0171760 in order to reduce the under recovery.

The balance of long-term Price Risk Management assets was approximately $51.8 million and $19.6 million at September 30, 2005 and December 31, 2004, respectively, an increase of approximately $32.2 million. The increase was primarily due to higher levels of activity associated with long-term physical gas transactions, related financial contracts associated with OERI's activities during the first nine months of 2005 and significantly higher natural gas futures.

The balance of Short-Term Debt was approximately $238.5 million and $125.0 million at September 30, 2005 and December 31, 2004, respectively, an increase of approximately $113.5 million or 90.8 percent. The increase is a result of higher working capital requirements primarily due to higher commodity prices at OG&E and Enogex and increasing daily operational needs of the Company.

The balance of Accounts Payable was approximately $499.2 million and $470.3 million at September 30, 2005 and December 31, 2004, respectively, an increase of approximately $28.9 million or 6.1 percent. The increase was primarily due to higher natural gas purchases in September 2005 as compared to December 2004.

The balance of Accrued Taxes was approximately $70.4 million and $13.2 million at September 30, 2005 and December 31, 2004, respectively, an increase of approximately $57.2 million. The increase was primarily due to an increase in the Company's estimated income tax liability and the timing of income tax payments.

The balance of current Price Risk Management liabilities was approximately $613.4 million and $102.9 million at September 30, 2005 and December 31, 2004, respectively, an increase of approximately $510.5 million. The increase was primarily due to higher natural gas prices associated with higher levels of activity associated with long-term physical gas transactions, related financial contracts associated with OERI's activities during the first nine months of 2005 and significantly higher natural gas futures. Approximately $65.4 million of the Company's natural gas storage transactions expired in October.

The balance of the Gas Imbalance liability was approximately $48.1 million and $22.4 million at September 30, 2005 and December 31, 2004, respectively, an increase of approximately $25.7 million. The increase was primarily due to increased natural gas storage obligations from higher natural gas prices of approximately $18.8 million from Enogex's marketing business and higher natural gas storage imbalances of approximately $6.2 million from Enogex's storage fields.

The balance of long-term Price Risk Management liabilities was approximately $53.9 million and $6.6 million at September 30, 2005 and December 31, 2004, respectively, an increase of approximately $47.3 million. The increase was primarily due to higher levels of activity associated with long-term physical gas transactions, related financial contracts associated with OERI's activities during the first nine months of 2005 and significantly higher natural gas futures.

Off-Balance Sheet Arrangements

Except as set forth below and in the Company's Form 10-K for the year ended December 31, 2004, there have been no significant changes in the Company's off-balance sheet arrangements.

Railcar Lease Agreement

See Note 12 of Notes to Condensed Consolidated Financial Statements for a discussion of OG&E's railcar lease agreement.

Liquidity and Capital Requirements

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

Interest Rate Swap Agreement

Fair Value Hedge

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

At September 30, 2005 and December 31, 2004, the fair values pursuant to OG&E's interest rate swap were approximately $3.6 million and $3.9 million, respectively, and the fair value hedge was classified as Current Assets – Price Risk Management and Deferred Charges and Other Assets – Price Risk Management, respectively, in the Condensed Consolidated Balance Sheets. A corresponding net increase of approximately $3.6 million and $3.9 million was reflected in Long-Term Debt at September 30, 2005 and December 31, 2004 as this fair value hedge was effective at September 30, 2005 and December 31, 2004. On September 1, 2005, the counterparty to OG&E's interest rate swap agreement exercised its right to change the termination date of the interest rate swap agreement from October 15, 2025 to October 15, 2005 in conjunction with the early redemption of long-term debt discussed below. On October 17, 2005, OG&E received approximately $5.3 million related to the termination of its interest rate agreement of which approximately $1.7 million is related to interest received and approximately $3.6 million is related to canceling the interest rate swap agreement, which will be amortized over the life of the long-term debt OG&E intends to issue later in 2005.

Future Capital Requirements

Capital Expenditures

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

Refinancing of Long-Term Debt

In August 2005, OG&E filed a Form S-3 Registration Statement to register the sale of up to $400.0 million of OG&E's unsecured debt securities. On October 15, 2005, OG&E paid at maturity its $110 million of 7.125 percent senior notes and redeemed its $110 million of 7.30 percent senior notes due October 15, 2005 at the principal amount plus a $3.6 million premium. The repayments were funded temporarily through the issuance of commercial paper by the Company and OG&E and borrowings under existing credit agreements which OG&E intends to replace through the issuance of long-term debt later in 2005.

Pension and Postretirement Benefit Plans

The Company has contributed approximately $32.0 million in 2005 to its pension plan, which represents the Company's 2004 pension expense, of which approximately $10.7 million was contributed during the third quarter of 2005. The contributions to the pension plan in 2005, in the form of cash, were discretionary contributions and were not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

Future Sources of Financing

Management expects that internally generated funds, long and short-term debt and proceeds from the sales of common stock pursuant to the Company's DRIP/DSPP 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.

Short-Term Debt

See Note 9 of Notes to Condensed Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Common Stock

In July 2005, the Company filed a Form S-3 Registration Statement to register 7,000,000 shares of the Company's common stock pursuant to the Company's DRIP/DSPP.

Critical Accounting Policies and Estimates

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

Accounting Pronouncements

See Note 2 of Notes to Condensed Consolidated Financial Statements for a discussion of 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 it appears unlikely in the near future that changes will occur to retail regulation in the states served by OG&E due to the significant problems faced by California in its electric deregulation efforts and other factors, significant changes are possible, which could significantly change the manner in which OG&E conducts its business. These developments at the federal and state levels are described in more detail in Notes 12 and 13 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q and in the Company's Form 10-K for the year ended December 31, 2004. OG&E currently has one important matter pending before the OCC. See Note 13 of Notes to Condensed Consolidated Financial Statements for a further discussion.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Except as disclosed otherwise in this Form 10-Q and in the Company's Form 10-K for the year ended December 31, 2004 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. See Notes 12 and 13 of Notes to Condensed Consolidated Financial Statements and Item 1 of Part II in this Form 10-Q and Notes 17 and 18 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2004 for a discussion of the Company's commitments and contingencies.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Risk Management

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

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

Interest Rate Risk

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

Except as set forth below, the Company's exposure to interest rate risk for changes in interest rates has not significantly changed since December 31, 2004. On April 1, 2005, Enogex terminated two interest rate swap agreements (with a total notional amount of $200 million) and received approximately $0.2 million related to this transaction. Since inception of the Enogex interest rate swap agreements, which converted $200 million of 8.125 percent fixed rate debt due

January 15, 2010 to a floating rate based upon the three and six month LIBOR, the Company has paid approximately $81.3 million in interest and has received approximately $29.9 million related to these agreements. The effective interest rate until maturity will be approximately 7.67 percent on this long-term debt.

On September 1, 2005, the counterparty to OG&E's interest rate swap agreement exercised its right to change the termination date of the interest rate swap agreement from October 15, 2025 to October 15, 2005 in conjunction with the early redemption of long-term debt discussed in Note 8 of Notes to Condensed Consolidated Financial Statements. On October 17, 2005, OG&E received approximately $5.3 million related to the termination of its interest rate agreement of which approximately $1.7 million is related to interest received and approximately $3.6 million is related to canceling the interest rate swap agreement, which will be amortized over the life of the long-term debt OG&E intends to issue later in 2005. See Notes 8 and 9 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q for a discussion of the Company's long-term and short-term debt activity.

Commodity Price Risk

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

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

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

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

(In millions)	Trading	Non-Trading
Commodity market risk, net	$ 1.3	$ 6.5

Item 4. Controls and Procedures.

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

("CFO"), of the effectiveness of the Company's disclosure controls and procedures, the CEO and CFO have concluded that the Company's disclosure controls and procedures are effective.

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

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

Reference is made to Part I, Item 3 of the Company's Form 10-K for the year ended December 31, 2004 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. As reported in Note 17 to the Company's Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2004, the Company has been involved in legal proceedings filed by Jack J. Grynberg in federal courts related to natural gas measurement. A ruling in this case by the special master was received in May 2005 which dismissed OG&E and all Enogex parties named in these proceedings. This ruling has been appealed to the District Court of Wyoming.

2. As reported in Part I, Item 3 of the Company's Form 10-K for the year ended December 31, 2004, OGE Energy Corp., Enogex, Central Oklahoma Oil and Gas Corp. ("COOG"), Natural Gas Storage Corporation ("NGSC") and individual shareholders of COOG and NGSC have been involved in legal proceedings relating to a gas storage agreement and associated agreements. In the actions pending against the individuals in the U.S. District Court for Western District of Oklahoma, the jury, on October 25, 2004, ruled in favor of the Company and Enogex for approximately $6.6 million. The individual defendants filed a motion for new trial. On March 23, 2005, the court entered an order: (i) denying the defendants' motion for new trial; (ii) denying the defendants' motion to stay; and (iii) granting the motion of OGE Energy Corp. and Enogex to allow registration of judgments in the U.S. District Court for the Southern District of Texas. On April 20, 2005, the defendants filed an appeal in the Tenth Circuit Court of Appeals. On September 14, 2005, the defendants posted a cash bond for approximately $6.9 million to stay the execution of the judgment pending appeal. The Company intends to continue to vigorously pursue its rights in conjunction with the remaining amounts owed under the judgments, plus interest. In a related action filed in Harris County, Texas in 2002 by NGSC and pending against the Company, on September 30, 2005 an order was entered by the Texas Court disposing of the entire Texas action based on a lack of jurisdiction.

3. As reported in Part I, Item 3 of the Company's Form 10-K for the year ended December 31, 2004, OG&E was sued by Kaiser-Francis Oil Company in District Court, Blaine County, Oklahoma. This case has been pending for more than 10 years. Plaintiff alleges that OG&E breached the terms of numerous contracts covering approximately 60 wells by failing to purchase gas from Plaintiff in amounts set forth in the contracts. Plaintiff seeks $25.0 million in take-or-pay damages and $1.8 million in underpayment damages. Over the objection and unsuccessful appeal by OG&E, Plaintiff has been permitted to amend its petition to include a claim based on theories of tort. Specifically, Plaintiff alleges, among other things, that OG&E intentionally and tortiously interfered with contracts by falsifying documents, sponsoring false testimony and putting forward legal defenses, which are known by OG&E to be without merit. If successful, Plaintiff believes that these theories could give Plaintiff a basis to seek punitive damages. This lawsuit was stayed pending the outcome of an appeal that OG&E filed in a similar case brought by Kaiser-Francis in Grady County. The case has been set for trial in January 2006. OG&E believes that, to the extent Plaintiff were successful on the merits of its claims of OG&E's failure to take gas in the Blaine County case, these amounts would be recoverable through its regulated electric rates. The claims related to tortiuous conduct, which OG&E believes at this time are without merit, would not appear to be recoverable in its electric rates.

In a similar case in Grady County, Oklahoma, the same plaintiff alleged that OG&E breached the terms of several gas purchase contracts in amounts set forth in the contracts. In 2001, the district court rendered a verdict against OG&E in the amount of approximately $8.0 million, including pre-judgment interest and attorneys' fees. OG&E filed an appeal and on May 18, 2004, the Court of Appeals issued an opinion reversing the judgment and remanding for a new trial. On October 17, 2005, a settlement was reached in the Grady County case whereby OG&E agreed to pay approximately $5.7 million to Kaiser-Francis. OG&E believes the settlement amount is recoverable through its regulated electric rates.

4. On July 22, 2005, Enogex Inc., Enogex Products Corporation ("EPC") and Enogex Gas Gathering, L.L.C. along with certain other unaffiliated co-defendants were served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs' own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including the Enogex companies, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs' wells. The plaintiffs' assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages in excess of $10,000, plus attorneys' fees and costs, and punitive damages in excess of $10,000. The Enogex companies filed a motion to dismiss the case which is scheduled to be heard on November 21, 2005. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Co., filed a cross claim against EPC seeking indemnification and/or contribution from EPC based upon the 1997 sale of a third party interest in one of EPC's natural gas processing plants. Based on its investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to vigorously defend this case.

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

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

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
7/1/05 – 7/31/05	66,500	$29.66	N/A	N/A
8/1/05 – 8/31/05	37,700	$28.81	N/A	N/A
9/1/05 – 9/30/05	18,700	$29.01	N/A	N/A

N/A – not applicable

Item 6. Exhibits.

Exhibit No.	**Description**
10.01	Stock purchase agreement dated September 21, 2005, by and between Enogex Inc. and Atlas Pipeline Partners, L.P. (Filed as Exhibit 10.01 to the Company's Form 8-K filed September 27, 2005 (File No. 1-12579) and incorporated by reference herein)
10.02	Credit agreement dated September 30, 2005, by and between the Company, Wachovia Bank, National Association, JPMorgan Chase Bank, Citibank, N.A., The Royal Bank of Scotland plc and Union Bank of California, N.A. (Filed as Exhibit 99.01 to the Company's Form 8-K filed October 5, 2005 (File No. 1-12579) and incorporated by reference herein)
10.03	Credit agreement dated September 30, 2005, by and between OG&E, Wachovia Bank, National Association, JPMorgan Chase Bank, Citibank, N.A., The Royal Bank of Scotland plc and Union Bank of California, N.A. (Filed as Exhibit 99.02 to the Company's Form 8-K filed October 5, 2005 (File No. 1-12579) and incorporated by reference herein)
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.
99.01	OCC Order in OG&E's gas transportation and storage case dated July 14, 2005. (Filed as Exhibit 99.02 to the Company's Form 8-K filed July 19, 2005 (File No. 1-12579) and incorporated by reference herein)

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

November 4, 2005

CERTIFICATIONS

I, Steven E. Moore, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: November 4, 2005

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

Exhibit 31.01

CERTIFICATIONS

I, James R. Hatfield, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: November 4, 2005

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

Exhibit 32.01

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

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

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

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

November 4, 2005

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

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