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

FORM 10-Q

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2006

OR

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

Commission File Number: 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 a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one): Large Accelerated Filer _X_ Accelerated Filer ___ Non-Accelerated Filer ___

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 March 31, 2006, 90,772,952 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED MARCH 31, 2006

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Item 1. Financial Statements.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	**March 31, 2006**	December 31, 2005
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 19.3**	$ 26.4
Accounts receivable, less reserve of $3.2 and $3.7, respectively	**335.1**	591.4
Accrued unbilled revenues	**40.3**	41.8
Fuel inventories	**67.6**	63.6
Materials and supplies, at average cost	**57.0**	56.5
Price risk management	**51.2**	116.5
Gas imbalances	**10.9**	32.0
Accumulated deferred tax assets	**14.0**	14.3
Fuel clause under recoveries	**44.0**	101.1
Recoverable take or pay gas charges	**---**	4.9
Prepayments and other	**20.2**	25.1
Total current assets	**659.6**	1,073.6
OTHER PROPERTY AND INVESTMENTS, at cost	**30.8**	29.2
PROPERTY, PLANT AND EQUIPMENT		
In service	**6,044.3**	5,996.3
Construction work in progress	**132.5**	101.8
Other	**3.2**	3.1
Total property, plant and equipment	**6,180.0**	6,101.2
Less accumulated depreciation	**2,599.9**	2,568.7
Net property, plant and equipment	**3,580.1**	3,532.5
In service of discontinued operations	**60.4**	60.6
Less accumulated depreciation	**25.9**	25.7
Net property, plant and equipment of discontinued operations	**34.5**	34.9
Net property, plant and equipment	**3,614.6**	3,567.4
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**32.6**	32.8
Intangible asset - unamortized prior service cost	**32.8**	32.8
Prepaid benefit obligation	**81.9**	90.2
Price risk management	**1.2**	9.0
McClain Plant deferred expenses	**23.3**	24.9
Unamortized loss on reacquired debt	**21.0**	21.3
Unamortized debt issuance costs	**9.7**	8.1
Other	**7.0**	7.2
Deferred charges and other assets of discontinued operations	**2.4**	2.4
Total deferred charges and other assets	**211.9**	228.7
TOTAL ASSETS	**$ 4,516.9**	$ 4,898.9

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

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

(In millions)	**March 31, 2006**	December 31, 2005
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ ---**	$ 30.0
Accounts payable	**295.3**	510.4
Dividends payable	**30.2**	30.1
Customers' deposits	**48.9**	47.8
Accrued taxes	**25.7**	67.1
Accrued interest	**23.7**	31.9
Tax collections payable	**9.3**	8.7
Accrued compensation	**24.0**	40.3
Price risk management	**53.1**	109.5
Gas imbalances	**23.9**	36.0
Provision for payments of take or pay gas	**---**	8.9
Other	**33.4**	29.9
Total current liabilities	**567.5**	950.6
LONG-TERM DEBT	**1,349.9**	1,350.8
COMMITMENTS AND CONTINGENCIES (NOTE 14)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**241.5**	234.5
Accumulated deferred income taxes	**811.7**	807.1
Accumulated deferred investment tax credits	**30.5**	31.7
Accrued removal obligations, net	**116.8**	114.2
Price risk management	**0.3**	10.7
Asset retirement obligation	**3.7**	3.6
Other	**17.6**	19.9
Total deferred credits and other liabilities	**1,222.1**	1,221.7
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**722.9**	715.5
Retained earnings	**745.2**	750.5
Accumulated other comprehensive loss, net of tax	**(90.7)**	(90.2)
Total stockholders' equity	**1,377.4**	1,375.8
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 4,516.9**	$ 4,898.9

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

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

	Three Months Ended March 31,	
(In millions, except per share data)	**2006**	2005
OPERATING REVENUES		
Electric Utility operating revenues	**$ 374.0**	$ 301.0
Natural Gas Pipeline operating revenues	**735.8**	964.3
Total operating revenues	**1,109.8**	1,265.3

COST OF GOODS SOLD (exclusive of depreciation shown below)		
Electric Utility cost of goods sold	**225.9**	165.0
Natural Gas Pipeline cost of goods sold	**662.6**	921.7
Total cost of goods sold	**888.5**	1,086.7
Gross margin on revenues	**221.3**	178.6
Other operation and maintenance	**105.5**	96.8
Depreciation	**44.9**	44.9
Taxes other than income	**19.1**	18.2
OPERATING INCOME	**51.8**	18.7
OTHER INCOME (EXPENSE)		
Other income	**6.7**	1.6
Other expense	**(1.2)**	(1.6)
Net other income	**5.5**	---
INTEREST INCOME (EXPENSE)		
Interest income	**1.5**	2.0
Interest on long-term debt	**(21.7)**	(19.0)
Allowance for borrowed funds used during construction	**1.0**	0.6
Interest on short-term debt and other interest charges	**(2.0)**	(1.6)
Net interest expense	**(21.2)**	(18.0)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**36.1**	0.7
INCOME TAX EXPENSE (BENEFIT)	**12.0**	(1.0)
INCOME FROM CONTINUING OPERATIONS	**24.1**	1.7
DISCONTINUED OPERATIONS (NOTE 5)		
Income from discontinued operations	**1.3**	5.8
Income tax expense	**0.5**	2.2
Income from discontinued operations	**0.8**	3.6
NET INCOME	**$ 24.9**	$ 5.3
BASIC AVERAGE COMMON SHARES OUTSTANDING	**90.6**	90.0
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**91.6**	90.5
BASIC EARNINGS PER AVERAGE COMMON SHARE		
Income from continuing operations	**$ 0.26**	$ 0.02
Income from discontinued operations, net of tax	**0.01**	0.04
NET INCOME	**$ 0.27**	$ 0.06
DILUTED EARNINGS PER AVERAGE COMMON SHARE		
Income from continuing operations	**$ 0.26**	$ 0.02
Income from discontinued operations, net of tax	**0.01**	0.04
NET INCOME	**$ 0.27**	$ 0.06
DIVIDENDS DECLARED PER SHARE	**$ 0.3325**	$ 0.3325

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

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

	Three Months Ended March 31,	
(In millions)	**2006**	2005
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income from continuing operations	**$ 24.1**	$ 1.7
Adjustments to reconcile net income from continuing operations to net cash provided from operating activities		
Depreciation	**44.9**	44.9
Deferred income taxes and investment tax credits, net	**4.5**	11.6
Gain on sale of assets	**(0.6)**	(0.2)
Stock-based compensation expense	**1.1**	---
Price risk management assets	**73.1**	(38.6)
Price risk management liabilities	**(67.4)**	31.3
Other assets	**7.7**	3.9
Other liabilities	**0.8**	(4.0)
Change in certain current assets and liabilities		
Accounts receivable, net	**256.3**	69.7
Accrued unbilled revenues	**1.5**	(2.5)
Fuel, materials and supplies inventories	**(4.5)**	34.7
Gas imbalance asset	**21.1**	(27.1)
Fuel clause under recoveries	**57.1**	24.6
Other current assets	**9.8**	8.9
Accounts payable	**(215.1)**	(46.4)

Customers' deposits	**1.1**	0.9
Accrued taxes	**(41.4)**	(12.2)
Accrued interest	**(8.2)**	(8.3)
Gas imbalance liability	**(12.1)**	(0.3)
Other current liabilities	**(17.5)**	(12.7)
Net Cash Provided from Operating Activities	**136.3**	79.9
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	**(84.5)**	(74.2)
Proceeds from sale of assets	**0.9**	0.4
Net Cash Used in Investing Activities	**(83.6)**	(73.8)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from long-term debt	**217.5**	---
Retirement of long-term debt	**---**	(23.0)
(Decrease) increase in short-term debt, net	**(250.0)**	29.0
Issuance of common stock	**1.9**	5.4
Dividends paid on common stock	**(30.1)**	(29.9)
Net Cash Used in Financing Activities	**(60.7)**	(18.5)
DISCONTINUED OPERATIONS		
Net cash provided from operating activities	**1.1**	1.6
Net cash used in investing activities	**(0.2)**	(0.5)
Net cash provided from financing activities	**---**	0.4
Net Cash Provided from Discontinued Operations	**0.9**	1.5
NET DECREASE IN CASH AND CASH EQUIVALENTS	**(7.1)**	(10.9)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**26.4**	11.1
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 19.3**	$ 0.2

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 related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through two business segments, the Electric Utility and the Natural Gas Pipeline segments. All significant intercompany transactions have been eliminated in consolidation.

The Electric Utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through 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. In March 2006, Enogex announced that Enogex Gas Gathering, L.L.C. ("Gathering"), a wholly-owned subsidiary of Enogex Inc., had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area (see Note 5 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 March 31, 2006 and December 31, 2005, the results of its operations for the three months ended March 31, 2006 and 2005, and the results of its cash flows for the three months ended March 31, 2006 and 2005, have been included and are of a normal recurring nature.

Due to seasonal fluctuations and other factors, the operating results for the three months ended March 31, 2006 are not necessarily indicative of the results that may be expected for the year ending December 31, 2006 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, 2005.

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.

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:

(In millions)	**March 31, 2006**	December 31, 2005
Regulatory Assets		
Fuel clause under recoveries	**$ 44.0**	$ 101.1
Income taxes recoverable from customers, net	**32.6**	32.8
McClain Plant deferred expenses	**23.3**	24.9
Unamortized loss on reacquired debt	**21.0**	21.3
Recoverable take or pay gas charges	---	4.9
Cogeneration credit rider under recovery	---	3.7
Miscellaneous	**0.2**	0.5
Total Regulatory Assets	**$ 121.1**	$ 189.2
Regulatory Liabilities		
Accrued removal obligations, net	**$ 116.8**	$ 114.3
Deferred gain on sale of assets	**3.4**	3.8
Cogeneration credit rider over recovery	**1.0**	---
Total Regulatory Liabilities	**$ 121.2**	$ 118.1

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

Stock-Based Compensation

The Company adopted SFAS No. 123 (Revised), "Share-Based Payment," effective January 1, 2006, which requires 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. See Note 2 for a further discussion related to the Company's stock-based compensation. The following table reflects pro forma net income and income per average common share for the three months ended March 31, 2005 had the Company elected to adopt the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," for options granted under the Company's stock-based employee compensation plans. For purposes of this pro forma disclosure, the value of the options was determined using a Black-Scholes option pricing formula and amortized to expense over the options' vesting periods. Pro forma information is not included for the three months ended March 31, 2006 as all share-based payments have been accounted for under SFAS No. 123(R).

(In millions, except per share data)	Three Months Ended March 31, 2005
Net income, as reported	$ 5.3
Add:	
Stock-based employee compensation expense included in reported net income, net of related tax effects	---
Deduct:	
Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	0.2
Pro forma net income	$ 5.1
Income per average common share	
Basic and diluted – as reported	$ 0.06
Basic and diluted – pro forma	$ 0.06

Reclassifications

Certain prior year amounts have been reclassified on the Condensed Consolidated Financial Statements to conform to the 2006 presentation.

2. Stock-Based Compensation

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

Prior to January 1, 2006, the Company accounted for the Plans under the recognition and measurement provisions of Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," as permitted by SFAS No. 123. The Company also previously adopted the disclosure provisions under SFAS No. 123 and SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." The Company recorded compensation expense of approximately $0.6 million pre-tax ($0.4 million after tax) during the three months ended March 31, 2005 related to its performance units. No stock-based employee compensation expense related to stock options was recognized for the three months ended March 31, 2005 as all options granted under those plans had an exercise price equal to the market value of the Company's common stock on the grant date. Effective January 1, 2006, the Company adopted SFAS No. 123(R) using the modified prospective transition method. Under that transition method, compensation cost recognized in the first quarter of 2006 includes: (i) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the fair value calculated in accordance with the provisions of SFAS No. 123(R); and (ii) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the fair value calculated in accordance with the provisions of SFAS No. 123(R). Results for prior periods have not been restated.

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

Prior to the adoption of SFAS No. 123(R), the Company presented all tax benefits of deductions resulting from the exercise of stock options or other share-based payments as operating cash flows in the Condensed Consolidated Statements of Cash Flows. SFAS 123(R) requires cash flows resulting in tax benefits from tax deductions in excess of the compensation cost recognized for share-based payments (excess tax benefits) to be classified as financing cash flows. No excess tax benefit was realized related to the Company's share-based payments during the three months ended March 31, 2006.

Performance Units

Under the Plans, the Company issues performance units which represent the value of one share of the Company's common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the Plans). Each performance unit is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant's number of full months of service during the three-year award cycle, further adjusted based on the achievement of the performance goals during the award cycle. The following table is a summary of the terms of the Company's performance units.

Condition	Settlement	Vesting Period	SFAS No. 123(R) Classification
Total Shareholder Return	2/3 – Stock (A)	3-year cliff	Equity
	1/3 – Cash	3-year cliff	Liability
Earnings Per Share	2/3 – Stock (A)	3-year cliff	Equity
	1/3 – Cash	3-year cliff	Liability

(A) All of the Company's 2006 performance units are settled in stock.

The performance units granted based on total shareholder return ("TSR") are contingently awarded and will be payable in cash or shares of the Company's common stock (other than performance units awarded in 2006, which will be payable only in shares of common stock) subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a three-year award cycle is dependent on the Company's TSR ranking relative to a peer group of companies. The performance units granted based on earnings per share ("EPS") are contingently awarded and will be payable in cash or shares of the Company's common stock (other than performance units awarded in 2006, which will be payable only in shares of common stock) based on the Company's EPS growth over a three-year award cycle compared to a target set at the time of the grant by the Compensation Committee of the Company's Board of Directors. If there is no payout for the performance units at the end of the three-year award cycle, the performance units are cancelled.

Performance Units – Total Shareholder Return

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded compensation expense of approximately $1.2 million pre-tax ($0.7 million after tax) during the three months ended March 31, 2006 related to the performance units based on TSR. The Company recorded compensation expense of approximately $0.6 million pre-tax ($0.4 million after tax) during the three months ended March 31, 2005 related to performance units based on TSR. The fair value of the performance units based on TSR was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units settled in stock is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Compensation expense for the performance units settled in cash is based on the change in the fair value of the performance units for each reporting period. This liability for the performance units will be remeasured at each reporting date until the date of settlement. Dividends are not accrued or paid during the performance period and, therefore, are not included in the fair value calculation. Expected price volatility is based on the historical volatility of the Company's common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the three-year award cycle. There are no post-vesting restrictions related to the Company's performance units based on TSR. The fair value of the performance units based on TSR was calculated based on the following assumptions at the grant date.

	2006	2005	2004
Expected dividend yield	4.9%	5.3%	6.5%
Expected price volatility	16.8%	22.3%	23.0%
Risk-free interest rate	4.66%	3.28%	2.47%
Expected life of units (in years)	2.85	2.85	2.94
Fair value of units granted	$ 22.93	$ 21.56	$ 20.10

A summary of the activity for the Company's performance units based on TSR at March 31, 2006 and changes during the three months ended March 31, 2006 are summarized in the following table. Following the end of a three-year

performance period, payout of the performance units based on TSR is determined by the Company's TSR for such period compared to a peer group and payout requires the approval of the Compensation Committee of the Company's Board of Directors. Payouts, if any, are made in stock and cash (other than payouts of performance units awarded in 2006, which will be made only in common stock) and are considered made when the payout is approved by the Compensation Committee.

(dollars in millions)	Number of Units	Stock Conversion Ratio (A)	Aggregate Intrinsic Value
Units Outstanding at 12/31/05	385,528	1 : 1	
Granted (B)	179,892	1 : 1	
Converted	(111,235)	1 : 1	$ 4.3
Forfeited	(3,688)	1 : 1	
Units Outstanding at 3/31/06	450,497	1 : 1	$ 19.1

(A) One performance unit = one share of the Company's common stock.
(B) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

A summary of the activity for the Company's non-vested performance units based on TSR at March 31, 2006 and changes during the three months ended March 31, 2006 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/05	274,293	$ 20.84
Granted (B)	179,892	$ 22.93
Vested	---	---
Forfeited	(3,688)	$ 21.83
Units Non-Vested at 3/31/06 (A)	450,497	$ 21.67

(A) Of the 450,497 performance units not vested at March 31, 2006, 399,017 performance units are assumed to vest at the end of the vesting period.
(B) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

At March 31, 2006, there was approximately $5.6 million in unrecognized compensation cost related to non-vested performance units based on TSR which is expected to be recognized over a weighted-average period of 2.15 years.

Performance Units – Earnings Per Share

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded compensation expense of approximately $0.6 million pre-tax ($0.4 million after tax) during the three months ended March 31, 2006 related to the performance units based on EPS. No compensation expense was recorded during the three months ended March 31, 2005 related to performance units based on EPS as the probable performance was below the threshold for payout. The fair value of the performance units based on EPS is based on grant date fair value which is equivalent to the price of one share of the Company's common stock on the date of grant. The fair value of performance units based on EPS varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. The Company reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to the Company's performance units based on EPS. The grant date fair value of the 2005 and 2006 performance units was $23.78 and $28.00, respectively.

A summary of the activity for the Company's performance units based on EPS at March 31, 2006 and changes during the three months ended March 31, 2006 are summarized in the following table. Following the end of a three-year performance period, payout of the performance units based on EPS growth is determined by the Company's growth in EPS for such period compared to a target set at the beginning of the three-year period by the Compensation Committee of the Company's Board of Directors and payout requires the approval of the Compensation Committee. Payouts, if any, are made in stock and cash (other than payouts of performance units awarded in 2006, which will be made only in common stock) and are considered made when approved by the Compensation Committee.

(dollars in millions)	Number of Units	Stock Conversion Ratio (A)	Aggregate Intrinsic Value
Units Outstanding at 12/31/05	46,539	1:1	
Granted (B)	59,964	1:1	
Converted	---	1:1	
Forfeited	(1,001)	1:1	
Units Outstanding at 3/31/06	105,502	1:1	$ 6.1

(A) One performance unit = one share of the Company's common stock.
(B) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

A summary of the activity for the Company's non-vested performance units based on EPS at March 31, 2006 and changes during the three months ended March 31, 2006 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/05	46,539	$ 23.78
Granted (B)	59,964	$ 28.00
Vested	---	---
Forfeited	(1,001)	$ 25.81
Units Non-Vested at 3/31/06 (A)	105,502	$ 26.16

(A) Of the 105,502 performance units not vested at March 31, 2006, 89,210 performance units are assumed to vest at the end of the vesting period.
(B) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

At March 31, 2006, there was approximately $3.7 million in unrecognized compensation cost related to non-vested performance units based on EPS which is expected to be recognized over a weighted-average period of 2.42 years.

Stock Options

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded compensation expense of less than $0.1 million during the three months ended March 31, 2006 related to stock options. During the first quarter of 2006 and during 2005, no stock options were granted under the 2003 Plan. Previous option awards were granted with an exercise price equal to the market value of the Company's common stock on the grant date which resulted in no stock-based employee compensation expense being recognized. The Company accounts for stock option grants as separate grants. The options granted under the Plans vest in one-third annual installments beginning one year from the date of grant and have a contractual life of 10 years. Each option is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. Dividends are not paid or accrued on unexercised options. The options provide for accelerated vesting if there is a change in control (as defined in the Plans). The fair value of each option grant under the Plans is estimated on the grant date using the Black-Scholes option pricing model and was $2.05 at the grant date for the stock options that are not fully vested at December 31, 2005.

A summary of the activity for the Company's options at March 31, 2006 and changes during the three months ended March 31, 2006 are summarized in the following table:

(dollars in millions)	Number of Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
Options Outstanding at 12/31/05	2,139,376	$ 22.20		
Granted	---	---		
Exercised	(99,258)	$ 19.03	$ 0.9	
Expired	(10,100)	$ 28.75		
Forfeited	(900)	$ 23.58		
Options Outstanding at 3/31/06	2,029,118	$ 22.32	$ 13.6	5.84 years
Options Fully Vested and Exercisable at 3/31/06	1,932,468	$ 22.25	$ 13.0	5.78 years

A summary of the activity for the Company's non-vested options at March 31, 2006 and changes during the three months ended March 31, 2006 are summarized in the following table:

	Number of Options	Weighted-Average Grant Date Fair Value
Options Non-Vested at 12/31/05	404,398	$ 1.95
Granted	---	---
Vested	(306,848)	$ 1.91
Forfeited	(900)	$ 2.05
Options Non-Vested at 3/31/06 (A)	96,650	$ 2.05

(A) Of the 96,650 stock options not vested at March 31, 2006, 92,564 stock options are assumed to vest at the end of the vesting period.

At March 31, 2006, there was less than $0.1 million in unrecognized compensation cost related to non-vested options which is expected to be recognized over a weighted-average period of 0.75 years.

The Company issues new shares to satisfy stock option exercises. The Company received approximately $1.9 million during the three months ended March 31, 2006 related to exercised stock options. No excess tax benefit was realized related to the Company's exercised stock options during the three months ended March 31, 2006.

3. Price Risk Management Assets and Liabilities

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

In the Company's Condensed Consolidated Balance Sheets at March 31, 2006 and December 31, 2005, the fair value of transactions with the same counterparty is presented on a gross basis, consistent with past practice. However, OGE Energy Resources, Inc. ("OERI") has energy trading contracts with set off provisions with various counterparties. If these transactions with the same counterparty were presented on a net basis in the Condensed Consolidated Balance Sheets, Price Risk Management assets and liabilities would be approximately $36.6 million and $37.3 million at March 31, 2006, respectively, and would be approximately $98.0 million and $92.8 million at December 31, 2005, respectively.

4. Accumulated Other Comprehensive Loss

The components of total comprehensive income for the three months ended March 31, 2006 and 2005, respectively, are as follows:

	Three Months Ended March 31,	
(In millions)	**2006**	2005
Net income	**$ 24.9**	$ 5.3
Other comprehensive income (loss), net of tax:		
Deferred hedging losses, net of tax	**(0.5)**	(1.8)
Amortization of cash flow hedge, net of tax	---	0.1
Total comprehensive income	**$ 24.4**	$ 3.6

The components of accumulated other comprehensive loss at March 31, 2006 and December 31, 2005 are as follows:

(In millions)	**March 31, 2006**	December 31, 2005
Minimum pension liability adjustment, net of tax	**$ (91.1)**	$ (91.1)
Deferred hedging gains, net of tax	**2.6**	3.1
Settlement and amortization of cash flow hedge, net of tax	**(2.2)**	(2.2)
Total accumulated other comprehensive loss, net of tax	**$ (90.7)**	$ (90.2)

Accumulated other comprehensive loss at both March 31, 2006 and December 31, 2005 included an after tax loss of approximately $91.1 million ($148.6 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, 2005. Any increases or decreases in the minimum pension liability will be reflected in Other Comprehensive Income or Loss in the fourth quarter.

5. Enogex – Discontinued Operations

In April 2005, Enogex Compression Company, LLC ("Enogex Compression") received an unsolicited offer to buy its interest in Enerven Compression Services, LLC ("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.

Enogex regularly evaluates 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 these evaluations, 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 Pipeline System Limited Partnership interest. This sale was completed on October 31, 2005. The Company received approximately $177.4 million in cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million is expected to be used to invest, over time, in strategic assets to diversify its asset base.

In March 2006, Enogex announced that its wholly-owned subsidiary, Gathering, had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction are approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and Enogex currently expects to record an after tax gain of approximately $34 million during the second quarter of 2006. The proceeds from the sale are expected to be used to invest, over time, in strategic assets to diversify its asset base.

The Condensed Consolidated Financial Statements of the Company have been reclassified to reflect Enogex Compression's sale of its Enerven interest, Enogex's sale of its EAPC interest and Gathering's sale of certain gas gathering assets in Kinta, Oklahoma, all of which were part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of Enerven, EAPC and the Gathering assets 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. Enogex Compression's sale of its Enerven interest and Enogex's sale of its EAPC interest were completed during 2005 and, therefore, there are no results of operations for these transactions during the three months ended March 31, 2006. Summarized financial information for the discontinued operations as of March 31 is as follows:

CONDENSED CONSOLIDATED STATEMENTS OF INCOME DATA

	Three Months Ended March 31,	
(In millions)	**2006**	2005
Operating revenues from discontinued operations	**$ 6.6**	$ 27.3
Income from discontinued operations before taxes	**1.3**	5.8

CONDENSED CONSOLIDATED BALANCE SHEET DATA

(In millions)	**March 31, 2006**	December 31, 2005
Plant in service of discontinued operations	**$ 60.4**	$ 60.6
Less accumulated depreciation	**25.9**	25.7
Net property, plant and equipment of discontinued operations	**$ 34.5**	$ 34.9
Total deferred charges and other assets of discontinued operations	**$ 2.4**	$ 2.4

6. 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.

	Three Months Ended March 31,	
(In millions)	**2006**	2005
NON-CASH INVESTING AND FINANCING ACTIVITIES		
Change in fair value of long-term debt due to interest rate swaps	**$ ---**	$ (6.8)

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

	Three Months Ended March 31,	
	2006	2005
Statutory federal tax rate	**35.0%**	35.0%
State income taxes, net of federal income tax benefit	**3.8**	4.1
Tax credits, net	**(3.3)**	(191.1)
ESOP dividends, 1997-2000 IRS examination and other	**(2.2)**	1.2
Effective income tax rate as reported	**33.3%**	(150.8)%

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.

8. Common Stock

For the three months ended March 31, 2006, there were 99,258 shares and 103,453 shares, respectively, of new common stock issued pursuant to the Company's Stock Incentive Plan, related to exercised stock options and payouts of earned performance units awarded in January 2003.

9. Earnings Per Share

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

	Three Months Ended March 31,	
(In millions)	**2006**	2005
Average Common Shares Outstanding		
Basic average common shares outstanding	**90.6**	90.0
Effect of dilutive securities:		
Employee stock options and unvested stock grants	**0.2**	0.1
Contingently issuable shares (performance units)	**0.8**	0.4
Diluted average common shares outstanding	**91.6**	90.5

During each of the three month periods ended March 31, 2006 and 2005, there was approximately 0.3 million shares related to outstanding employee stock options which were not included in the calculation of diluted earnings per average common share because the effect of including those shares is anti-dilutive as the exercise price of the stock options exceeded the average common stock market price during the respective period.

10. Long-Term Debt

At March 31, 2006, the Company is in compliance with all of its debt agreements.

Long-Term Debt with Optional Redemption Provisions

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

SERIES	DATE DUE	AMOUNT
3.11% - 3.39%	Garfield Industrial Authority, January 1, 2025	**$ 47.0**
3.20% - 3.42%	Muskogee Industrial Authority, January 1, 2025	**32.4**
3.03% - 3.31%	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.

11. Short-Term Debt

The short-term debt balance was approximately $250.0 million at December 31, 2005. There was no short-term debt outstanding at March 31, 2006. In accordance with SFAS No. 6, "Classification of Short-Term Obligations Expected to Be Refinanced, an Amendment of Accounting Research Bulletin No. 43, Chapter 3A," $220.0 million in commercial paper and bank borrowings was used to temporarily fund $220 million of long-term debt of OG&E that had matured or been called for redemption in the fourth quarter of 2005. This commercial paper was classified as long-term debt at December 31, 2005 as OG&E planned to refinance this amount. Subsequently, OG&E issued $220 million of long-term debt in January 2006 and repaid the outstanding commercial paper and bank borrowings. The following table shows the Company's lines of credit in place, commercial paper outstanding and available cash at March 31, 2006.

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

Entity	Amount Available	Amount Outstanding	Weighted-Average Interest Rate	Maturity
OGE Energy Corp. (B)	$ 600.0	$ ---	N/A	September 30, 2010 (A)
OG&E (C)	150.0	---	N/A	September 30, 2010 (A)
OGE Energy Corp.	15.0	---	N/A	April 6, 2006 (D)
	765.0	---	N/A	
Cash	19.3	N/A	N/A	N/A
Total	$ 784.3	$ ---	N/A	

(A) During 2005, the Company and OG&E entered into revolving credit agreements totaling $750 million, 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.
(B) This bank facility is available to back up a maximum of $300.0 million of the Company's commercial paper borrowings and to provide an additional $300.0 million in revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At March 31, 2006, there were no outstanding commercial paper borrowings.
(C) This bank facility is available to back up a maximum of $100.0 million of OG&E's commercial paper borrowings and to provide an additional $50.0 million in revolving credit borrowings. At March 31, 2006, OG&E had approximately $0.2 million supporting a letter of credit and no outstanding commercial paper borrowings.
(D) The Company did not renew this line of credit when it expired on April 6, 2006.

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

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

12. Retirement Plans and Postretirement Benefit Plans

The details of net periodic benefit cost of the pension plan (including the restoration of retirement income plan) and the postretirement benefit plans included in the Condensed Consolidated Financial Statements are as follows:

Net Periodic Benefit Cost

	Pension Plan and Restoration of Retirement Income Plan	
	Three Months Ended March 31,	
(In millions)	**2006**	2005
Service cost	**$ 5.1**	$ 4.8
Interest cost	**7.8**	7.6
Return on plan assets	**(9.6)**	(8.5)
Amortization of net loss	**4.2**	3.6
Amortization of unrecognized prior service cost	**1.5**	1.6
Net periodic benefit cost	**$ 9.0**	$ 9.1

	Postretirement Benefit Plans	
	Three Months Ended March 31,	
(In millions)	**2006**	2005
Service cost	**$ 0.9**	$ 0.8
Interest cost	**3.0**	2.6
Return on plan assets	**(1.4)**	(1.4)
Amortization of transition obligation	**0.7**	0.7
Amortization of net loss	**2.2**	1.3
Amortization of unrecognized prior service cost	**0.5**	0.5
Net periodic benefit cost	**$ 5.9**	$ 4.5

Pension Plan Funding

The Company previously disclosed in its Form 10-K for the year ended December 31, 2005 that it may contribute up to $90 million to its pension plan during 2006. In April 2006, the Company contributed approximately $30.0 million to the pension plan and currently expects to contribute an additional $60.0 million to the pension plan during the remainder of 2006. Any expected contributions to the pension plan during 2006 are discretionary contributions anticipated to be in the form of cash and are not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

13. Report of Business Segments

The Company's Electric Utility operations are conducted through OG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy. The Company's Natural Gas Pipeline operations are conducted through Enogex. Enogex is engaged in the transportation and storage of natural gas, the gathering and processing of natural gas and the marketing of natural gas. Other Operations for the three months ended March 31, 2006 and 2005 primarily includes unallocated corporate expenses, interest expense on commercial paper and interest expense on long-term debt. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. The following tables summarize the results of the Company's business segments for the three months ended March 31, 2006 and 2005.

Three Months Ended March 31, 2006	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 374.0**	**$ 763.2**	**$ ---**	**$ (27.4)**	**$ 1,109.8**
Cost of goods sold	**237.7**	**678.0**	**---**	**(27.2)**	**888.5**
Gross margin on revenues	**136.3**	**85.2**	**---**	**(0.2)**	**221.3**
Other operation and maintenance	**79.7**	**28.6**	**(2.8)**	**---**	**105.5**
Depreciation	**33.1**	**10.2**	**1.6**	**---**	**44.9**
Taxes other than income	**13.7**	**4.3**	**1.1**	**---**	**19.1**
Operating income (loss)	**9.8**	**42.1**	**0.1**	**(0.2)**	**51.8**
Other income	**0.2**	**6.0**	**0.5**	**---**	**6.7**
Other expense	**(1.1)**	**---**	**(0.1)**	**---**	**(1.2)**
Interest income	**1.0**	**2.5**	**1.4**	**(3.4)**	**1.5**
Interest expense	**(13.7)**	**(8.1)**	**(4.3)**	**3.4**	**(22.7)**
Income tax expense (benefit)	**(2.7)**	**16.3**	**(1.5)**	**(0.1)**	**12.0**
Income (loss) from continuing operations	**(1.1)**	**26.2**	**(0.9)**	**(0.1)**	**24.1**
Income from discontinued operations	**---**	**0.8**	**---**	**---**	**0.8**
Net income (loss)	**$ (1.1)**	**$ 27.0**	**$ (0.9)**	**$ (0.1)**	**$ 24.9**
Total assets	**$3,202.3**	**$ 1,423.7**	**$ 1,849.6**	**$ (1,958.7)**	**$ 4,516.9**

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

Three Months Ended March 31, 2006	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	**$ 64.6**	**$ 159.9**	**$ 677.1**	**$ (138.4)**	**$ 763.2**
Operating income	**$ 22.1**	**$ 16.4**	**$ 3.6**	**$ ---**	**$ 42.1**
Income from continuing operations	**$ 26.2**	**$ 10.7**	**$ 2.2**	**$ (12.9)**	**$ 26.2**

Three Months Ended March 31, 2005	Electric Utility (A)	Natural Gas Pipeline (B)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 301.0	$ 985.2	$ ---	$ (20.9)	$ 1,265.3
Cost of good sold	175.0	933.6	---	(21.9)	1,086.7
Gross margin on revenues	126.0	51.6	---	1.0	178.6
Other operation and maintenance	77.4	22.5	(3.1)	---	96.8
Depreciation	33.1	10.0	1.8	---	44.9
Taxes other than income	12.7	4.3	1.2	---	18.2
Operating income	2.8	14.8	0.1	1.0	18.7
Other income (loss)	0.7	---	0.9	---	1.6
Other expense	(0.5)	---	(1.1)	---	(1.6)
Interest income	1.6	0.6	0.3	(0.5)	2.0
Interest expense	(9.7)	(7.9)	(2.9)	0.5	(20.0)
Income tax expense (benefit)	(3.4)	3.0	(0.9)	0.3	(1.0)
Income (loss) from continuing operations	(1.7)	4.5	(1.8)	0.7	1.7
Income from discontinued operations	---	3.6	---	---	3.6
Net income (loss)	$ (1.7)	$ 8.1	$ (1.8)	$ 0.7	$ 5.3

Total assets	$ 3,036.3	$ 1,674.7	$ 1,692.6	$ (1,656.2)	$ 4,747.4

(A) 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 quarter of 2005 of approximately $3.4 million. 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 at that time was deferred as a regulatory asset to better reflect the purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration. 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.

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

Three Months Ended March 31, 2005	Transportation and Storage	Gathering and Processing	Marketing (C)	Eliminations	Total
(In millions)					
Operating revenues	$ 51.7	$ 143.5	$ 903.7	$ (113.7)	$ 985.2
Operating income (loss)	$ 9.1	$ 9.7	$ (4.0)	$ ---	$ 14.8
Income (loss) from continuing operations	$ 4.1	$ 6.0	$ (2.4)	$ (3.2)	$ 4.5

(C) 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 ($4.7 million after tax or $0.05 per share) 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.

14. Commitments and Contingencies

Except as set forth below and in Note 15, the circumstances set forth in Notes 14 and 15 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2005 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 14 to the Company's Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2005, 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 against the individual shareholders of COOG and NGSC in the U.S. District Court for Western District of Oklahoma, the jury, in 2004, ruled in favor of the Company and Enogex for approximately $6.6 million ("Thrash Fraudulent Transfer Judgment"). In April 2005, the defendants filed an appeal in the Tenth Circuit Court of Appeals and on September 14, 2005, the defendants posted a cash bond for approximately $6.9 million to stay the execution of the Thrash Fraudulent Transfer Judgment pending appeal. On December 30, 2005, the parties reached a settlement of the Thrash Fraudulent Transfer Judgment and other COOG-related matters discussed in the Company's Form 10-K for the year ended December 31, 2005. On March 8, 2006, the individual defendants paid approximately $5.2 million (the "Settlement Amount") to the Company and Enogex. Thereafter, the parties dismissed the pending appeal of the Thrash Fraudulent Transfer Judgment to the Tenth Circuit. The Settlement Amount has been accounted for as a gain in the Company's Condensed Consolidated Financial Statements in the first quarter of 2006. The Company now considers these matters closed.

Calpine Corporation Bankruptcy

Calpine Corporation, Calpine Energy Services, L.P., and several other affiliates (collectively "Calpine") voluntarily filed for Chapter 11 bankruptcy protection from creditors on December 20, 2005 (Case No. 05-60200 (BRL)) United States Bankruptcy Court, S.D. of New York. Enogex provides natural gas transportation services pursuant to long-term contracts to two Calpine-owned power generation plants in Oklahoma. Calpine is continuing to operate the plants and request services pursuant to the contracts. The total unpaid amount due to Enogex from Calpine is approximately $0.3 million which has been fully reserved on the Company's books. Approximately $0.2 million of this amount relates to Calpine's dispute of a portion of a monthly demand payment in July 2005. Enogex believes this amount is due and owing and subject to recoupment and/or set off rights. The remaining amounts relate to unpaid invoices for transportation services provided to Calpine immediately prior to its bankruptcy filing.

It remains unknown whether Calpine, in its bankruptcy proceedings, will affirm or reject these agreements with Enogex.

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

Environmental Laws and Regulations

OG&E

Air

On March 25, 2005, the Environmental Protection Agency ("EPA") issued the Clean Air Mercury Rule ("CAMR") to limit mercury emissions from coal-fired boilers. The CAMR 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 requires each state to adopt the requirements of the federal rule into a state implementation plan. However, the CAMR does not preclude states from developing more stringent mercury reduction requirements. The state of Oklahoma is currently considering three options for implementation of the rule, the most significant differences between the options are related to requirements for mercury controls and allocation and availability of allowances. OG&E is currently participating in the rulemaking process and anticipates the rulemaking to be completed by the end of 2006. Because rulemaking is in progress, the cost to install any mercury controls is uncertain at this time but is expected to be significant to meet Phase II requirements in 2018. The state implementation plan will also require continuous monitoring of mercury

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emissions from OG&E's coal-fired boilers beginning in 2009. The cost of monitoring has not yet been established because the state implementation plan and monitoring technology are still being developed. However, the cost to comply with the CAMR monitoring requirements 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.

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 legal counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Condensed Consolidated Financial Statements. Except as otherwise stated above, in Note 15 below, in Item 1 of Part II of this Form 10-Q, in Notes 14 and 15 of Notes to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2005 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.

15. Rate Matters and Regulation

Except as set forth below, the circumstances set forth in Note 15 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2005 appropriately represent, in all material respects, the current status of any regulatory matters.

Completed Regulatory Matters

Acquisition of Power Plant

On July 9, 2004, OG&E completed the acquisition of NRG McClain LLC's 77 percent interest in the 520 megawatt ("MW") natural gas-fired combined cycle NRG McClain Station ("McClain Plant"). This transaction was intended to satisfy the requirement in the 2002 agreed-upon settlement of an OG&E rate case (the "Settlement Agreement") to acquire electric generation of not less than 400 MW's. 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 closing of the purchase of the McClain Plant was subject to approval from the FERC. The FERC's July 2, 2004 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. As part of the July 2, 2004 order, OG&E agreed to undertake the following mitigation measures: (i) install certain transmission facilities designed to result in up to 600 MW's of available transfer capability ("ATC") from the Redbud Energy LP ("Redbud") facility to the OG&E control area; (ii) pending completion of these transmission upgrades, provide up to 600 MW's of ATC into OG&E's control area from the Redbud plant through changes to the dispatch of OG&E's generating units; and (iii) hire an independent market monitor to oversee OG&E's activity in its control area until the SPP implements a market monitor for the SPP regional transmission organization ("RTO"). OG&E completed the installation of the capital improvements and notified the FERC in writing on May 31, 2005 that these were completed. OG&E's obligation to redispatch its system to make 600 MW's of ATC available to the Redbud power plant terminated upon completion of the transmission upgrades. The independent market monitor described above has submitted six 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 improper behavior with regard to access to OG&E's transmission system. In August 2005, the market monitor initiated a special investigation into the circumstances surrounding the denial by the SPP of a request by Redbud for 440 MW's in June 2005 of firm transmission service to OG&E. In its third quarter 2005 report, the market monitor concluded that differences in the SPP modeling assumptions and an error in modeling made by the SPP were the primary causes for the denial of service. The market monitor further stated that, if the FERC's July 2, 2004 order was based on the assumption that the McClain generating unit was not running to serve OG&E's load, the ATC created by the mitigation upgrades completed by OG&E in response to the FERC's July 2, 2004 order matched the claims made by OG&E. On

September 21, 2005, the FERC issued a letter requesting OG&E to provide information to confirm that the transmission facilities that OG&E constructed to mitigate the effects of the acquisition of the McClain interest resulted in 600 MW's of ATC from Redbud to the OG&E control area. On October 3, 2005, OG&E responded that the facilities it constructed complied with the settlement the FERC approved regarding the acquisition of the McClain interest and resulted in the 600 MW's of ATC. Redbud responded that, when it requested transmission service commencing in June 2005 after the facilities were completed, the SPP denied Redbud's request for service and, therefore, argued that the ATC was not created. OG&E explained that the SPP's denial of service to Redbud was due to an error by the SPP. Nonetheless Redbud and OG&E have filed additional pleadings addressing the ATC. On March 30, 2006, the FERC requested additional information from OG&E and the SPP. In the March 30 request, the FERC asked OG&E for the source of the 440 MW's of firm power to supply to its customers. Also in the March 30 request, the FERC requested that the SPP provide certain details regarding all reservations approved between the time the FERC issued the July 2, 2004 order and the time the Redbud request for 440 MW's was made. On April 10, 2006, OG&E and the SPP filed comments in response to the March 30 request by the FERC. On April 19, 2006, the FERC issued a notice of telephone conference which was held on April 26, 2006 where the FERC asked additional questions regarding the April 10, 2006 submissions by OG&E and the SPP. While OG&E believes that no further action is warranted in this matter, it cannot predict what action the FERC could ultimately take.

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 Filing and FERC 2006 Fuel Filing

The FERC requires all intrastate pipelines offering 311 service to file a rate case every three years. Enogex must file its next rate case no later than October 1, 2007.

As required by the fuel tracker provisions of the Statement of Operating Conditions, Enogex made its annual fuel filing for the 2006 fuel year on November 15, 2005. As agreed in the prior Section 311 settlement, the fuel filing sets forth an East Zone fuel percentage and a West Zone fuel percentage to be recalculated annually to replace the system-wide fuel percentage previously utilized annually for the whole Enogex system. By order dated April 13, 2006, the FERC approved and accepted Enogex's annual fuel tracker filing and approved the zonal fuel factors as fair and equitable effective January 1, 2006.

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. Because the required integrated service was not available in the marketplace from parties other than Enogex, 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 exceeding the prescribed MDQ's or MHQ's, it pays an overrun service charge. During each of the three month periods ended March 31, 2006 and 2005, OG&E paid Enogex approximately $11.9 million for gas transportation and storage services.

On July 14, 2005, the OCC issued an order in this case approving a $41.9 million annual recovery. 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 approximately $1.2 million to $3.7 million annually. This amount was approximately $1.2 million in 2005 and is projected to be approximately $1.6 million in 2006. The OCC's order required 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. OG&E began refunding this obligation in

September 2005 through its automatic fuel adjustment clause. The balance of the refund obligation was approximately $4.1 million at March 31, 2006.

In connection with the Enogex gas transportation and storage agreement, OG&E also recorded a refund obligation in Arkansas of approximately $1.1 million at December 31, 2005. OG&E provided to the APSC the OCC evidence and above findings showing that the Arkansas refund was calculated consistently with the Oklahoma refund. OG&E applied the refund obligation to its fuel clause under recoveries balance in April and customers began receiving this refund in April 2006 and will continue through March 2007.

Competitive Bidding, Prudence Reviews and Other Rules 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." 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 and other matters. Rules were adopted by the OCC on January 18, 2006 and became effective on April 3, 2006. The new rules: (i) establish a competitive procurement process for purchase of long-term electric generation and long-term fuel supplies; (ii) clarify existing law by requiring that a prudence review of utility fuel and generation procurement be conducted no less frequently than every two years; (iii) require a utility to submit an integrated resource plan to the OCC every three years, with the first plan due on October 1, 2006; and (iv) establish a process whereby a utility may seek pre-approval for recovery of costs associated with transmission upgrades, generation facility modifications caused by environmental requirements and the purchase or construction of generation facilities. OG&E does not expect these rules to have a significant impact on its operations.

Pending Regulatory Matters

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2003 and 2004

The OCC routinely audits activity in OG&E's fuel adjustment clause for each calendar year. 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 completed Oklahoma rate case. On August 25, 2005, the OCC Staff filed Cause No. PUD 200500327 regarding "Application of the Public Utility Division Director for Public Hearing to Review and Monitor OG&E's Fuel Adjustment Clause for Calendar Year 2004." On September 27, 2005, the OCC consolidated these two proceedings into one proceeding. Intervenors in this proceeding include the Oklahoma Industrial Energy Consumers, AES Shady Point ("AES"), Redbud and PowerSmith Cogeneration Project, L.P. The parties have agreed to continue the matter. A new procedural schedule is expected to be issued in May with a hearing proposed by the parties in September 2006.

OG&E Wind Power Filing

On December 22, 2005, the Company issued a press release announcing that OG&E had entered into a non-binding letter of intent to purchase a 120 MW wind farm planned for construction in northwestern Oklahoma. Invenergy Wind Development Oklahoma LLC ("Invenergy LLC") would develop the new wind power-generation facility to be owned and operated by OG&E. The wind farm, north of Woodward in Harper County, is expected to cost approximately $195 million to construct, including the cost of transmission interconnection facilities. A definitive Agreement To Engineer, Procure and Construct Wind Generation Energy System ("EPC Contract") was reached on February 20, 2006, subject to various conditions. Those conditions include agreement by the parties as to certain exhibits to the EPC Contract, approval of the EPC Contract by the OG&E Board of Directors and approval of the EPC Contract by the governing body for Invenergy LLC, all of which have been completed. In addition, 90 days subsequent to the occurrence of these events, OG&E or Invenergy LLC have the unilateral right to terminate the EPC Contract if certain additional events have not occurred, including the following: (i) OCC approval of the terms of the EPC Contract and of a recovery rider providing OG&E the opportunity to recover the costs associated with the wind facility, including transmission interconnection and transmission upgrade costs; (ii) completion by the SPP of all necessary transmission studies; (iii) Invenergy LLC's acquisition of certain land agreements; (iv) Invenergy LLC's execution of a contract acceptable to OG&E with a balance of work contractor; and (v) Invenergy LLC's acquisition of certain permits. If all of these conditions are met, the new wind farm is expected to be constructed and producing power on or before December 31, 2006. On April 6, 2006, a settlement agreement was filed with the OCC which, among other things, requested approval of the wind power EPC contract and a recovery rider for up to $205 million in construction and allowance for funds used during construction; the settlement also indicated that OG&E shall file for a general rate review during 2009 which will permit the OCC to issue an order no later than December 31, 2009 placing the

wind farm in OG&E's rate base. The settlement agreement satisfied requirement (i) above. On April 11, 2006, the administrative law judge ("ALJ") in this proceeding recommended approval of the settlement agreement. On April 28, 2006, the OCC issued a unanimous order approving the settlement agreement. OG&E expects to file an application with the APSC in June 2006 for approval to allocate to Arkansas the portion of the wind project not being recovered in rates in Oklahoma and expects to include recovery for the Arkansas portion in its Arkansas rate case filing in July 2006.

OG&E Arkansas Rate Case Filing

Beginning in January 2006, OG&E began developing a rate case filing for the Arkansas jurisdiction. OG&E filed a notice with the APSC on May 1, 2006 of its intent to file a rate case in July 2006 requesting an increase in electric rates. The amount of the requested increase has not yet been determined.

OG&E SO2 Allowance Filing

On February 10, 2006, OG&E, the OCC Staff and AES filed a joint application with the OCC to determine the treatment of proceeds received from OG&E's sale of sulfur dioxide ("SO2") allowances and how these proceeds will be shared between OG&E and its customers for any sales after December 31, 2005. In the application, the parties propose that AES be held harmless from any reduction in OG&E's coal costs caused by the sale of SO2 allowances and that the proceeds of such sales are shared 80 percent with OG&E's Oklahoma customers and the remaining 20 percent to OG&E. A credit rider was requested to pass the proceeds from the sale of the SO2 allowances to Oklahoma customers. Any proceeds from the sale of SO2 allowances in the Arkansas and the FERC jurisdictions will flow through OG&E's automatic fuel adjustment clause. On March 16, 2006, OG&E filed testimony in support of the joint application. The OCC Staff and AES filed testimony on April 21. Responsive testimony is due May 5. All parties are expected to file rebuttal testimony on May 18 and a hearing is scheduled for May 30 before the ALJ.

Uniform Fuel Adjustment Clause Filing

On January 23, 2006, the Director of the Public Utility Division of the OCC filed Cause No. PUD 200600012 regarding an application to review the OCC's regulation of the automatic rate adjustment clauses of all public energy utilities operating in Oklahoma and subject to the OCC's jurisdiction. A technical conference for electric utilities was held on March 17, 2006 and a second technical conference is expected in May 2006. At this time, OG&E does not believe the outcome of this proceeding will significantly impact the Company.

Southwest Power Pool

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. On September 19, 2005, the FERC rejected the June 15, 2005 filing; however, the FERC provided guidance for the SPP's follow-up filing. On January 4, 2006, the SPP filed its follow-up filing in Docket No. ER06-451 by submitting tariff revisions to incorporate imbalance energy market and market monitoring procedures. On March 20, 2006, the FERC issued an order on the proposed tariff revisions which conditionally accepted a portion of the filing and suspended and rejected other portions of the filing. As a result, the scheduled implementation date of the imbalance energy market has been delayed from May 1, 2006 to October 1, 2006. OG&E expects minimal additional costs related to market systems implementation due to the delay in the effective date of the imbalance energy market.

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 replaced the supply margin assessment test and issued: (1) interim requirements for the FERC jurisdictional electric utilities that 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 does not 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 market-based rate sellers pending the outcome of 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 applied the interim tests to OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but did not pass the market share screen in the OG&E control area. OG&E and OERI provided an explanation as to why their failure of the market share screen in the OG&E control area 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, intervened and protested OG&E's and OERI's filing.

On June 7, 2005, the FERC issued an order on OG&E's and OERI's market-based rate filing. Because OG&E and OERI failed the market share screen for OG&E's control area, the FERC established hearing procedures to investigate whether OG&E and OERI may continue to sell power at market-based rates in OG&E's control area. The order established a rebuttable presumption that OG&E and OERI have the ability to exercise market power in the OG&E control area. OG&E and OERI were requested to provide additional information that demonstrates to the FERC that they cannot exercise market power in the first-tier markets as well. However, the order conditionally allows OG&E and OERI to sell power in first-tier markets subject to OG&E and OERI providing additional information that clearly shows that they pass the market share screen for the first-tier markets. OG&E and OERI provided that additional information on July 7, 2005. On August 8, 2005, OG&E and OERI informed the FERC that they will: (i) adopt the FERC default rate mechanism for sales of one week or less to loads that sink in OG&E's control area; and (ii) commit not to enter into any sales with a duration of between one week and one year to loads that sink in OG&E's control area. OG&E and OERI also informed the FERC that any new agreements for long-term sales (one year or longer in duration) to loads that sink in OG&E's control area will be filed with the FERC and that OG&E and OERI will not make such sales under their respective market-based rate tariffs. No party filed interventions or comments on OG&E's and OERI's August 8, 2005 filing. On January 20, 2006, the FERC issued a Notice of Institution of Proceeding and Refund Effective Date for the purpose of establishing the date from which any subsequent market-based sales would be subject to refund in the event the FERC concludes after investigation that the rates for such sales are not just and reasonable. The refund effective date was March 27, 2006.

On March 21, 2006, the FERC issued an order conditionally accepting OG&E's and OERI's proposal to mitigate the presumption of market power in the OG&E control area. First, the FERC accepted the additional information related to first-tier markets submitted by OG&E and OERI, and concluded that OG&E and OERI satisfy the FERC's generation market power standard for directly interconnected first-tier control areas. Second, the FERC directed the Company to make certain revisions to its mitigation proposal and file a cost-based rate tariff for short-term sales (one week or less) made within the OG&E control area. The FERC also expanded the scope of the proposed mitigation to all sales made within the OG&E control area (instead of only to sales sinking to load within the OG&E control area). On April 20, 2006, the Company submitted: (i) a compliance filing containing the specified revisions to the Company's market-based rate tariffs and the new cost-based rate tariff; and (ii) a request for rehearing asking the FERC to reconsider its expanded mitigation directive contained in the March 21, 2006 order.

State Legislative Initiatives

Oklahoma

The 2006 legislative session began in February with approximately 2,000 bills being filed. While many theoretically could have an impact on the Company's operations, it appears that none of the bills, in the form filed, are expected to have a material impact on the Company. One bill, House Bill 1386 was introduced in the 2005 session and was carried over into the 2006 session. That bill, if passed, could have an impact on the Company's ability to compete with other utility providers. The bill 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. OG&E believes current case law authorizes utilities to serve and expand in an area described above. House Bill 1386 would codify OG&E's belief. The bill failed to be heard for a final vote in the Senate in 2005 and it carried over to the current legislative session. It is unknown at this time if the bill will be heard.

16. 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, 2005.

	March 31, 2006		December 31, 2005	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 52.4**	**$ 52.4**	$ 125.4	$ 125.4
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 53.4**	**$ 53.4**	$ 120.1	$ 120.1
Long-Term Debt				
Senior Notes	**$ 807.0**	**$ 827.3**	$ 587.8	$ 612.2
Other	---	---	220.0	220.0

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 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. See Note 3 for a discussion of Enogex's energy trading contracts with set off provisions.

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

Introduction

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

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

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries ("Enogex") and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. In March 2006, Enogex announced that Enogex Gas Gathering, L.L.C. ("Gathering"), a wholly-owned subsidiary of Enogex Inc., had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area (see "Results of Operations – Enogex – Discontinued Operations" for a further discussion).

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; availability and prices of raw materials; federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company's 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 Risk Factors and Exhibit 99.01 to the Company's Form 10-K for the year ended December 31, 2005.

Overview

Summary of Operating Results

Quarter ended March 31, 2006 as compared to quarter ended March 31, 2005

The Company reported net income of approximately $24.9 million, or $0.27 per diluted share, as compared to approximately $5.3 million, or $0.06 per diluted share, for the three months ended March 31, 2006 and 2005, respectively. The increase in net income during the three months ended March 31, 2006 as compared to the same period in 2005 was primarily due to:

- OG&E reported a net loss of approximately $1.1 million, or $0.01 per diluted share of the Company's common stock, as compared to a net loss of approximately $1.7 million, or $0.02 per diluted share, during the three months ended March 31, 2006 and 2005, respectively;
- Enogex's operations, including discontinued operations, reported net income of approximately $27.0 million, or $0.29 per diluted share of the Company's common stock, as compared to approximately $8.1 million, or $0.09 per diluted share, during the three months ended March 31, 2006 and 2005, respectively; and
- a net loss at the holding company of approximately $1.0 million, or $0.01 per diluted share, during the three months ended March 31, 2006 as compared to a net loss of approximately $1.1 million, or $0.01 per diluted share, during the same period in 2005.

Regulatory Matters

Gas Transportation and Storage Agreement

As part of the 2002 agreed-upon settlement of an OG&E rate case (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. Because the required integrated service was not available in the marketplace from parties other than Enogex, 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 exceeding the prescribed MDQ's or MHQ's, it pays an overrun service charge. During each of the three month periods ended March 31, 2006 and 2005, OG&E paid Enogex approximately $11.9 million for gas transportation and storage services.

On July 14, 2005, the OCC issued an order in this case approving a $41.9 million annual recovery. 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 approximately $1.2 million to $3.7 million annually. This amount was approximately $1.2 million in 2005 and is projected to be approximately $1.6 million in 2006. The OCC's order required 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. OG&E began refunding this obligation in September 2005 through its automatic fuel adjustment clause. The balance of the refund obligation was approximately $4.1 million at March 31, 2006.

In connection with the Enogex gas transportation and storage agreement, OG&E also recorded a refund obligation in Arkansas of approximately $1.1 million at December 31, 2005. OG&E provided to the APSC the OCC evidence and above findings showing that the Arkansas refund was calculated consistently with the Oklahoma refund. OG&E applied the refund obligation to its fuel clause under recoveries balance in April and customers began receiving this refund in April 2006 and will continue through March 2007.

OG&E Wind Power Filing

On December 22, 2005, the Company issued a press release announcing that OG&E had entered into a non-binding letter of intent to purchase a 120 megawatt ("MW") wind farm planned for construction in northwestern Oklahoma. Invenergy Wind Development Oklahoma LLC ("Invenergy LLC") would develop the new wind power-generation facility to be owned and operated by OG&E. The wind farm, north of Woodward in Harper County, is expected to cost approximately $195 million to construct, including the cost of transmission interconnection facilities. A definitive Agreement To Engineer, Procure and Construct Wind Generation Energy

System ("EPC Contract") was reached on February 20, 2006, subject to various conditions. Those conditions include agreement by the parties as to certain exhibits to the EPC Contract, approval of the EPC Contract by the OG&E Board of Directors and approval of the EPC Contract by the governing body for Invenergy LLC, all of which have been completed. In addition, 90 days subsequent to the occurrence of these events, OG&E or Invenergy LLC have the unilateral right to terminate the EPC Contract if certain additional events have not occurred, including the following: (i) OCC approval of the terms of the EPC Contract and of a recovery rider providing OG&E the opportunity to recover the costs associated with the wind facility, including transmission interconnection and transmission upgrade costs; (ii) completion by the Southwest Power Pool of all necessary transmission studies; (iii) Invenergy LLC's acquisition of certain land agreements; (iv) Invenergy LLC's execution of a contract acceptable to OG&E with a balance of work contractor; and (v) Invenergy LLC's acquisition of certain permits. If all of these conditions are met, the new wind farm is expected to be constructed and producing power on or before December 31, 2006. On April 6, 2006, a settlement agreement was filed with the OCC which, among other things, requested approval of the wind power EPC contract and a recovery rider for up to $205 million in construction and allowance for funds used during construction; the settlement also indicated that OG&E shall file for a general rate review during 2009 which will permit the OCC to issue an order no later than December 31, 2009 placing the wind farm in OG&E's rate base. The settlement agreement satisfied requirement (i) above. On April 11, 2006, the administrative law judge in this proceeding recommended approval of the settlement agreement. On April 28, 2006, the OCC issued a unanimous order approving the settlement agreement. OG&E expects to file an application with the APSC in June 2006 for approval to allocate to Arkansas the portion of the wind project not being recovered in rates in Oklahoma and expects to include recovery for the Arkansas portion in its Arkansas rate case filing in July 2006.

Outlook

The Company previously disclosed in its Form 10-K for the year ended December 31, 2005 that its 2006 earnings guidance was $159 million to $169 million of net income, or $1.75 to $1.85 per diluted share as shown in the table below. The Company has increased its 2006 earnings guidance, excluding any gains on asset sales, to $187 million to $205 million of net income, or $2.05 to $2.25 per diluted share, assuming approximately 91.6 million average diluted shares outstanding, cash flow from operations of between $368 million and $386 million and an effective tax rate of 36.3 percent. The change in earnings guidance is due to an increase in the projected earnings at Enogex and a decrease in the net loss at the holding company. The outlook for OG&E remains unchanged (see "Outlook" in the Company's Form 10-K for the year ended December 31, 2005 for a description of the underlying assumptions related to OG&E's earnings guidance).

	Earnings guidance per 2005 10-K		Revised earnings guidance per Q1 2006 10-Q	
(In millions, except per share data)	Dollars	Diluted EPS	Dollars	Diluted EPS
OG&E	$124 - $128	$1.36 - $1.40	$124 - $128	$1.36 - $1.40
Enogex	$44 - $48	$0.48 - $0.53	$69 - $82	$0.75 - $0.90
Holding Company	($7) – ($9)	($0.08) – ($0.10)	($5) – ($6)	($0.05) – ($0.06)
Total	$159 - $169	$1.75 - $1.85	$187 - $205	$2.05 - $2.25

Key assumptions for 2006 are:

Enogex

For 2006, Enogex's earnings guidance has been increased from $44 million to $48 million, or $0.48 to $0.53 per diluted share, to $69 million to $82 million, or $0.75 to $0.90 per diluted share.

- Total Enogex gross margin of approximately $303 million to $324 million as compared to approximately $272 million to $279 million in the original 2006 earnings guidance:
  - Transportation and storage gross margin contribution of approximately $135 million as compared to approximately $116 million in the original 2006 earnings guidance:
    - The increase in gross margin is primarily due to increased gains from imbalances and higher current and forecasted demand fees from new agreements; and
    - Approximately 70 percent of Enogex's transportation and storage contracts are firm contracts with revenues primarily from gas transportation contracts with utilities and independent power producers in Oklahoma.
  - Gathering and processing gross margin contribution of approximately $159 million to $180 million as compared to approximately $147 million to $154 million in the original 2006 earnings guidance:
    - Gross margin increase in Enogex's gathering and processing business in 2006 primarily due to higher commodity spreads offset by lower contractual gains as a result of lower natural gas prices;
    - Volumes in Enogex's gathering and processing business remain relatively flat from 2005;
    - Natural gas prices are $6.98 to $7.45 per Million British thermal unit ("MMBtu") in 2006;

- Commodity spreads are $2.56 to $3.46 per MMBtu in 2006 as compared to $1.95 to $2.22 per MMBtu in the original 2006 earnings guidance and average natural gas liquids prices are $0.99 to $1.09 per gallon in 2006 as compared to $0.94 to $1.16 per gallon in the original 2006 earnings guidance; and
- Enogex's gathering and processing business is projecting approximately 270 new well connections in 2006.

- Marketing gross margin contribution of approximately $9 million remains unchanged;

- Operating and maintenance expenses increase approximately $7 million primarily due to increased employee and benefit costs;
- Interest expense remains relatively flat in 2006;
- Capital expenditures for investment in Enogex's pipeline system are approximately $60 to $70 million in 2006; and
- Funding for the Company's pension plan may be up to $90 million in 2006, of which up to $7.4 million may be allocated to Enogex.

Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets have not been included in the 2006 earnings guidance.

Holding Company

For 2006, the holding company's earnings guidance now reflects a lower expected loss of $5 million to $6 million, or $0.05 to $0.06 per diluted share, from a loss of $7 million to $9 million, or $0.08 to $0.10 per diluted share.

- Decrease in effective tax rate at the holding company as a result of tax credits previously recorded at OG&E now recorded at the holding company;
- Funding for the Company's pension plan may be up to $90 million in 2006, of which approximately $12.7 million may be allocated to the holding company; and
- Interest expense decreases slightly in 2006 due to lower levels of short-term debt offset by higher short-term interest rates.

Results of Operations

The following discussion and analysis presents factors which affected the Company's consolidated results of operations for the three months ended March 31, 2006 as compared to the same period in 2005 and the Company's consolidated financial position at March 31, 2006. The following information should be read in conjunction with the Condensed Consolidated Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

	Three Months Ended March 31,	
(In millions, except per share data)	**2006**	2005
Operating income	**$ 51.8**	$ 18.7
Net income	**$ 24.9**	$ 5.3
Basic average common shares outstanding	**90.6**	90.0
Diluted average common shares outstanding	**91.6**	90.5
Basic earnings per average common share	**$ 0.27**	$ 0.06
Diluted earnings per average common share	**$ 0.27**	$ 0.06
Dividends declared per share	**$ 0.3325**	$ 0.3325

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

Operating Income (Loss) by Business Segment

	Three Months Ended March 31,	
(In millions)	**2006**	2005
OG&E (Electric Utility)	**$ 9.8**	$ 2.8
Enogex (Natural Gas Pipeline) (A)	**42.1**	14.8
Other Operations (B)	**(0.1)**	1.1
Consolidated operating income	**$ 51.8**	$ 18.7

(A) Excludes discontinued operations. See "Enogex – Discontinued Operations" for a further discussion.
(B) 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 March 31, 2006	2005
Operating revenues	**$ 374.0**	$ 301.0
Cost of goods sold	**237.7**	175.0
Gross margin on revenues	**136.3**	126.0
Other operation and maintenance	**79.7**	77.4
Depreciation	**33.1**	33.1
Taxes other than income	**13.7**	12.7
Operating income	**9.8**	2.8
Other income	**0.2**	0.7
Other expense	**1.1**	0.5
Interest income	**1.0**	1.6
Interest expense	**13.7**	9.7
Income tax benefit	**2.7**	3.4
Net loss	**$ (1.1)**	$ (1.7)
Operating revenues by classification		
Residential	**$ 137.9**	$ 114.2
Commercial	**88.4**	70.2
Industrial	**85.4**	65.7
Public authorities	**37.1**	29.1
Sales for resale	**14.9**	13.1
Provision for refund on gas transportation and storage case	**---**	(1.0)
System sales revenues	**363.7**	291.3
Off-system sales revenues	**0.5**	0.4
Other	**9.8**	9.3
Total operating revenues	**$ 374.0**	$ 301.0
MWH (A) sales by classification (in millions)		
Residential	**1.8**	1.9
Commercial	**1.3**	1.3
Industrial	**1.7**	1.7
Public authorities	**0.6**	0.6
Sales for resale	**0.4**	0.3
System sales	**5.8**	5.8
Off-system sales	**---**	---
Total sales	**5.8**	5.8
Number of customers	**748,695**	734,820
Average cost of energy per KWH (B) - cents		
Fuel	**3.538**	2.403
Fuel and purchased power	**3.839**	2.813
Degree days (C)		
Heating		
Actual	**1,499**	1,665
Normal	**1,963**	1,963
Cooling		
Actual	**31**	1
Normal	**8**	8

(A) Megawatt-hour.

(B) Kilowatt-hour.

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

Quarter ended March 31, 2006 as compared to quarter ended March 31, 2005

OG&E's operating income increased approximately $7.0 million during the three months ended March 31, 2006 as compared to the same period in 2005 primarily due 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 $136.3 million during the three months ended March 31, 2006 as compared to approximately $126.0 million during the same period in 2005, an increase of approximately $10.3 million or 8.2 percent. The gross margin increased primarily due to:

- rate increases authorized in the OCC order in December 2005, which increased the gross margin by approximately $9.7 million;
- price variance due to sales and customer mix, which increased the gross margin by approximately $2.9 million;
- new customer growth in OG&E's service territory, which increased the gross margin by approximately $2.3 million; and
- increased peak demand by industrial customers in OG&E's service territory, which increased the gross margin by approximately $1.7 million.

These increases in gross margin were partially offset by milder weather in OG&E's service territory, which reduced the gross margin by approximately $5.9 million.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $184.7 million during the three months ended March 31, 2006 as compared to approximately $132.3 million during the same period in 2005, an increase of approximately $52.4 million or 39.6 percent due to a higher average cost of natural gas per kwh. Purchased power costs were approximately $53.0 million during the three months ended March 31, 2006 as compared to approximately $42.7 million during the same period in 2005, an increase of approximately $10.3 million or 24.1 percent primarily due to an increase in purchased power costs while various OG&E power plants were being overhauled.

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.

Other operating and maintenance expenses were approximately $79.7 million during the three months ended March 31, 2006 as compared to approximately $77.4 million during the same period in 2005, an increase of approximately $2.3 million or 3.0 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages, pension and other employee expenses of approximately $5.3 million;
- higher allocations from the holding company of approximately $3.3 million primarily due to higher miscellaneous corporate expenses; and
- timing differences in legal expenses of approximately $2.3 million.

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

- increase in capitalized work of approximately $7.5 million; and
- lower materials and supplies expense of approximately $1.6 million.

The other operating and maintenance expense variance includes other operating and maintenance expenses associated with the acquisition of NRG McClain LLC's 77 percent interest in the 520 megawatt natural gas-fired combined cycle NRG McClain Station ("McClain Plant"), which ceased being recorded as a regulatory asset on July 8, 2005.

Taxes other than income were approximately $13.7 million during the three months ended March 31, 2006 as compared to approximately $12.7 million during the same period in 2005, an increase of approximately $1.0 million or 7.9 percent, primarily due to increased ad valorem taxes. This variance includes ad valorem taxes associated with the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.

Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating income. Other income was approximately $0.2 million during the three months ended March 31, 2006 as compared to approximately $0.7 million during the same period in 2005, a decrease of approximately $0.5 million or 71.4 percent. The decrease in other income was primarily due to a decrease of approximately $0.3 million from contract work performed by OG&E in 2006 and a gain of approximately $0.2 million from the sale of miscellaneous assets during the first quarter of 2005.

Other expense includes, among other things, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions and expenses. Other expense was approximately

$1.1 million during the three months ended March 31, 2006 as compared to approximately $0.5 million during the same period in 2005, an increase of approximately $0.6 million primarily due to an adjustment to natural gas inventory of approximately $0.4 million to correct reported volumes in a prior period.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $12.7 million during the three months ended March 31, 2006 as compared to approximately $8.1 million during the same period in 2005, an increase of approximately $4.6 million or 56.8 percent. The increase in net interest expense was primarily due to:

- increased interest on debt associated with the McClain Plant acquisition, which OG&E ceased recording as a regulatory asset on July 8, 2005, of approximately $2.3 million;
- increased interest of approximately $0.9 million due to increased short-term borrowings;
- 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 of approximately $0.8 million; and
- lower interest income of approximately $0.6 million primarily due to the interest portion of an income tax refund related to prior periods which was received in the first quarter of 2005.

Income tax benefit was approximately $2.7 million during the three months ended March 31, 2006 as compared to approximately $3.4 million during the same period in 2005, a decrease of approximately $0.7 million or 20.6 percent primarily due to a lower pre-tax loss for OG&E.

Enogex – Continuing Operations

	Three Months Ended March 31,	
(Dollars in millions)	**2006**	2005
Operating revenues	**$ 763.2**	$ 985.2
Cost of goods sold	**678.0**	933.6
Gross margin on revenues	**85.2**	51.6
Other operation and maintenance	**28.6**	22.5
Depreciation	**10.2**	10.0
Taxes other than income	**4.3**	4.3
Operating income	**42.1**	14.8
Other income	**6.0**	---
Interest income	**2.5**	0.6
Interest expense	**8.1**	7.9
Income tax expense	**16.3**	3.0
Income from continuing operations	**$ 26.2**	$ 4.5
New well connects	**55**	48
Gathered volumes – TBtud (A)	**0.93**	0.83
Incremental transportation volumes – TBtud	**0.45**	0.35
Total throughput volumes – TBtud	**1.38**	1.18
Natural gas processed – Mmcfd (B)	**520**	500
Natural gas liquids sold (keep-whole) – million gallons	**74**	78
Natural gas liquids sold (POL and fixed-fee) – million gallons	**3**	4
Total natural gas liquids sold – million gallons	**77**	82
Average sales price per gallon	**$ 0.912**	$ 0.746

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

Quarter ended March 31, 2006 as compared to quarter ended March 31, 2005

Enogex's operating income increased approximately $27.3 million during the three months ended March 31, 2006 as compared to the same period in 2005 primarily due to increased gross margins in each of Enogex's businesses largely as a result of a favorable commodity environment. The increases in gross margin were partially offset by higher operating and maintenance expenses.

Transportation and storage contributed approximately $40.8 million of Enogex's gross margin during the three months ended March 31, 2006 as compared to approximately $24.0 million during the same period in 2005, an increase of approximately $16.8 million or 70.0 percent. The gross margin increased primarily due to:

- better management of gas pipeline imbalances as Enogex reduced its exposure to gas imbalances while taking advantage of favorable market prices as compared to the first quarter of 2005, in addition to the transfer of approximately $1.8 million of gas imbalance liabilities to the gathering and processing business in the first quarter of 2006, which increased the gross margin by approximately $5.8 million;
- improved recovery of fuel as Enogex experienced fuel under recoveries in the first quarter of 2005 and fuel over recoveries in the first quarter of 2006, which increased the gross margin by approximately $4.2 million;

  storage field hedging gains, which increased the gross margin by approximately $3.5 million;

-
- increased commodity and interruptible revenues primarily due to higher volumes, which increased the gross margin by approximately $1.4 million; and
- increased demand fees primarily due to the negotiation of a new contract, which increased the gross margin by approximately $0.8 million.

Gathering and processing contributed approximately $38.2 million of Enogex's gross margin during the three months ended March 31, 2006 as compared to approximately $29.2 million during the same period in 2005, an increase of approximately $9.0 million or 30.8 percent. Gathering gross margins increased approximately $4.3 million or 25.8 percent during the three months ended March 31, 2006 as compared to the same period in 2005. The gathering gross margin increased primarily due to:

- decrease in the reserve for over recovered fuel established during the fourth quarter of 2005, which increased the gross margin by approximately $3.2 million;
- contractual fuel gains primarily due to higher gathered volumes, which increased the gross margin by approximately $1.6 million; and
- higher natural gas prices on natural gas sales reflective of opportunities in the marketplace, which increased the gross margin by approximately $1.3 million.

These increases in the gathering gross margin were partially offset by the transfer of imbalance liabilities from the transportation and storage business, which reduced the gross margin by approximately $1.8 million.

Processing gross margins increased approximately $4.7 million or 37.6 percent during the three months ended March 31, 2006 as compared to the same period in 2005 primarily due to increased net keep-whole margins primarily due to favorable commodity spreads, which increased the gross margin by approximately $4.8 million.

Marketing contributed approximately $6.2 million of Enogex's gross margin during the three months ended March 31, 2006 as compared to a reduction in gross margin of approximately $1.6 million during the same period in 2005, an increase of approximately $7.8 million. The gross margin increased primarily due to:

- a correction to the accounting procedure for park and loan transactions (natural gas storage transactions) in the first quarter of 2005, which decreased the gross margin in the first quarter of 2005 by approximately $7.7 million (see Note 13 of Notes to Condensed Consolidated Financial Statements); and
- more favorable market conditions on transportation contracts, which increased the gross margin by approximately $6.7 million.

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

- mark-to-market timing losses in natural gas storage activity and lower volumes, which reduced the gross margin by approximately $4.2 million; and
- less favorable market prices and opportunities in trading activity, which reduced the gross margin by approximately $2.2 million.

Enogex's other operating and maintenance expenses were approximately $28.6 million during the three months ended March 31, 2006 as compared to approximately $22.5 million during the same period in 2005, an increase of approximately $6.1 million or 27.1 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages, pension and other employee expenses of approximately $2.7 million;
- higher outside service costs of approximately $1.6 million primarily related to business development projects and work performed to maintain the integrity and safety of Enogex's pipeline; and
- higher allocations from the holding company of approximately $0.9 million due to higher miscellaneous corporate expenses.

Other income was approximately $6.0 million during the three months ended March 31, 2006. There was no other income for the three months ended March 31, 2005. The increase was primarily due to a litigation settlement of approximately $5.2 million (see Note 14 of Notes to Condensed Consolidated Financial Statements) and the sale of a small gathering section of Enogex's pipeline of approximately $0.5 million in the first quarter of 2006.

Net interest expense was approximately $5.6 million during the three months ended March 31, 2006 as compared to approximately $7.3 million during the same period in 2005, a decrease of approximately $1.7 million or 23.3 percent. The decrease in net interest expense is primarily due to an increase in interest income on cash investments from interest earned on the cash proceeds from the sale of Enogex Arkansas Pipeline Corporation ("EAPC") in October 2005.

Income tax expense was approximately $16.3 million during the three months ended March 31, 2006 as compared to approximately $3.0 million during the same period in 2005, an increase of approximately $13.3

million primarily due to higher pre-tax income for Enogex.

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

an increase in net income of approximately $4.3 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business. These increases in net income include:

- litigation settlement (see Note 14 of Notes to Condensed Consolidated Financial Statements) of approximately $3.2 million;
- income from discontinued operations of approximately $0.8 million; and
- the sale of a small gathering section of Enogex's pipeline of approximately $0.3 million.

For the three months ended March 31, 2005, Enogex's net income, including the discontinued operations discussed below under the caption "Enogex – Discontinued Operations," was approximately $8.1 million. During 2005, Enogex had a decrease in net income of approximately $1.1 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business. The decrease in net income was due to a correction recorded in 2005 to the accounting procedure for park and loan transactions in 2004 of approximately $4.7 million partially offset by income from discontinued operations of approximately $3.6 million.

Enogex – Discontinued Operations

In April 2005, Enogex Compression Company, LLC ("Enogex Compression") received an unsolicited offer to buy its interest in Enerven Compression Services, LLC ("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.

Enogex regularly evaluates 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 these evaluations, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in EAPC, which held the NOARK Pipeline System Limited Partnership interest. This sale was completed on October 31, 2005. The Company received approximately $177.4 million in cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million is expected to be used to invest, over time, in strategic assets to diversify its asset base.

In March 2006, Enogex announced that its wholly-owned subsidiary, Gathering, had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction are approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and Enogex currently expects to record an after tax gain of approximately $34 million during the second quarter of 2006. The proceeds from the sale are expected to be used to invest, over time, in strategic assets to diversify its asset base.

As a result of these sale transactions, Enogex Compression's interest in Enerven, Enogex's interest in EAPC and Gathering's sale of certain gas gathering assets in Kinta, Oklahoma, which were part of the Natural Gas Pipeline segment, have been reported as discontinued operations for the three months ended March 31, 2006 and 2005 in the Condensed Consolidated Financial Statements. Enogex Compression's sale of its Enerven interest and Enogex's sale of its EAPC interest were completed during 2005 and, therefore, there are no results of operations for these transactions during the three months ended March 31, 2006. Results for the discontinued operations are summarized and discussed below.

	Three Months Ended March 31,	
(In millions)	**2006**	2005
Operating revenues	**$ 6.6**	$ 27.3
Cost of goods sold	**4.1**	15.7
Gross margin on revenues	**2.5**	11.6
Other operation and maintenance	**0.8**	2.1
Depreciation	**0.3**	1.7
Taxes other than income	**0.1**	0.4
Operating income	**1.3**	7.4

Other expense	---	0.4
Net interest expense	---	1.2
Income tax expense	**0.5**	2.2
Net income	**$ 0.8**	$ 3.6

Quarter ended March 31, 2006 as compared to quarter ended March 31, 2005

Gross margin decreased approximately $9.1 million or 78.4 percent during the three months ended March 31, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005 and a decrease in natural gas purchases and sales due to a decrease in natural gas transported.

Operating and maintenance expense decreased approximately $1.3 million or 61.9 percent during the three months ended March 31, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005.

Depreciation expense decreased approximately $1.4 million or 82.4 percent during the three months ended March 31, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005 and ceasing depreciation expense in January 2006 when the Gathering assets in Kinta were reported as a discontinued operation.

Net interest expense decreased approximately $1.2 million or 100.0 percent during the three months ended March 31, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005 and the use of a portion of the sale proceeds to repay long-term debt.

Income tax expense decreased approximately $1.7 million or 77.3 percent during the three months ended March 31, 2006 as compared to the same period in 2005 primarily due to sale of EAPC in October 2005 and lower operating income for the Gathering assets in Kinta during the three months ended March 31, 2006.

Financial Condition

The balance of Accounts Receivable was approximately $335.1 million and $591.4 million at March 31, 2006 and December 31, 2005, respectively, a decrease of approximately $256.3 million or 43.3 percent primarily due to lower natural gas sales volume activity by Enogex and lower natural gas prices in the first quarter of 2006.

The balance of current Price Risk Management assets was approximately $51.2 million and $116.5 million at March 31, 2006 and December 31, 2005, respectively, a decrease of approximately $65.3 million or 56.1 percent. The decrease was primarily due to lower natural gas prices associated with OGE Energy Resources, Inc. ("OERI") short-term physical natural gas purchase transactions and associated financial contracts. A reduction in the volume of OERI's short-term physical natural gas activity and associated financial contracts outstanding at March 31, 2006 from December 31, 2005 also contributed to the decrease.

The balance of Gas Imbalance asset was approximately $10.9 million and $32.0 million at March 31, 2006 and December 31, 2005, respectively, a decrease of approximately $21.1 million or 65.9 percent. The Gas Imbalance asset is comprised of planned or managed imbalances related to OERI's business, referred to as park and loan transactions, and pipeline and natural gas liquids imbalances, which are operational imbalances. Park and loan transactions were approximately $0.6 million and $15.7 million at March 31, 2006 and December 31, 2005, respectively, a decrease of approximately $15.1 million or 96.2 percent due to the expiration of 2005 park and loan transactions in OERI's business activities. Operational imbalances were approximately $10.1 million and $16.3 million at March 31, 2006 and December 31, 2005, respectively, a decrease of approximately $6.2 million or 38.0 percent primarily due to lower volumes in third party operational balancing agreements, storage and pricing.

The balance of Fuel Clause Under Recoveries was approximately $44.0 million and $101.1 million at March 31, 2006 and December 31, 2005, respectively, a decrease of approximately $57.1 million or 56.5 percent. The decrease in fuel clause under recoveries was due to the amount billed to OG&E's customers during the three months ended March 31, 2006 exceeding OG&E's cost of fuel. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel cost in periods of rising prices above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under or over recovery. OG&E expects to recover the under recovery later in 2006.

The balance of Short-Term Debt was approximately $30.0 million at December 31, 2005. There was no short-term debt outstanding at March 31, 2006. The decrease was primarily due to lower working capital requirements in the first quarter of 2006.

The balance of Accounts Payable was approximately $295.3 million and $510.4 million at March 31, 2006 and December 31, 2005, respectively, a decrease of approximately $215.1 million or 42.1 percent. The decrease was primarily due to lower natural gas purchases and prices in March 2006 as compared to December 2005, less purchased power and timing of outstanding checks clearing the bank.

The balance of Accrued Taxes was approximately $25.7 million and $67.1 million at March 31, 2006 and December 31, 2005, respectively, a decrease of approximately $41.4 million or 61.7 percent primarily due to a federal income tax payment made in the first quarter of 2006.

The balance of Accrued Compensation was approximately $24.0 million and $40.3 million at March 31, 2006 and December 31, 2005, respectively, a decrease of approximately $16.3 million or 40.4 percent primarily due to incentive compensation payments made in the first quarter of 2006.

The balance of current Price Risk Management liabilities was approximately $53.1 million and $109.5 million at March 31, 2006 and December 31, 2005, respectively, a decrease of approximately $56.4 million or 51.5 percent. The decrease was primarily due to lower natural gas prices associated with OERI's short-term physical natural gas purchase transactions and associated financial contracts. A reduction in the volume of OERI's short-term physical natural gas activity and associated financial contracts outstanding at March 31, 2006 from December 31, 2005 also contributed to the decrease.

Off-Balance Sheet Arrangements

There have been no significant changes in the Company's off-balance sheet arrangements.

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.

Future Capital Requirements

Capital Expenditures

The Company's current 2006 to 2008 construction program includes continued investment in OG&E's and Enogex's assets. To reliably meet the increased electricity needs of OG&E's customers during the foreseeable future, OG&E will continue to invest to maintain the integrity of the delivery system. As previously disclosed in the Company's Form 10-K for the year ended December 31, 2005, the Company's construction program did not include capital expenditures of up to $205 million associated with OG&E's wind power project which was approved by the OCC on April 28, 2006. OG&E expects to fund the wind power project with a capital contribution from the holding company and the issuance of long-term debt later in 2006.

Other Regulatory Matters

Later in 2006, OG&E is planning to issue a request for proposal ("RFP") for additional capacity in 2008. In addition, OG&E has determined that additional base load capacity may be needed in 2011 and 2012. OG&E is also participating in the Public Service Company ("PSO") RFP process for securing additional base load capacity to meet PSO's capacity needs in 2011 of between approximately 450 and 600 MW's.

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 17, 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 replaced with the proceeds from the issuance of $110 million of 5.15 percent senior notes and $110 million of 5.75 percent senior notes in January 2006.

Pension and Postretirement Benefit Plans

The Company previously disclosed in its Form 10-K for the year ended December 31, 2005 that it may contribute up to $90 million to its pension plan during 2006. In April 2006, the Company contributed approximately $30.0 million to the pension plan and currently expects to contribute an additional $60.0 million to the pension plan during the remainder of 2006. Any expected contributions to the pension plan during 2006 are discretionary contributions anticipated to be in the form of cash and are not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

Future Sources of Financing

Management expects that internally generated funds, long and short-term debt, proceeds from the sales of common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan and proceeds from dividends and stock sales 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 11 of Notes to Condensed Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Critical Accounting Policies and Estimates

The Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements contain information that is pertinent to Management's Discussion and Analysis. In preparing the Condensed Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Condensed Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material affect on the Company's Condensed Consolidated Financial Statements particularly as they relate to pension expense and impairment estimates. However, the Company believes it has taken reasonable but conservative positions, where assumptions and estimates are used, in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, impairment estimates, contingency reserves, accrued removal obligations, regulatory assets and liabilities, unbilled revenue for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and fair value and cash flow hedges. 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, 2005.

Accounting Pronouncements

As a result of adopting SFAS No. 123(R) "Share-Based Payment" on January 1, 2006 using the modified prospective transition method, the Company recorded compensation cost of approximately $1.8 million pre-tax ($1.1 million after tax) during the three months ended March 31, 2006 related to the Company's share-based payments. Also, as a result of adopting SFAS No. 123(R), the Company recorded a cumulative effect adjustment of approximately $0.4 million pre-tax ($0.2 million after tax) on January 1, 2006 for outstanding share-based compensation grants at December 31, 2005. The Company determined that the cumulative effect adjustment was immaterial for presentation purposes and is, therefore, included in Other Operation and Maintenance Expense in the Condensed Consolidated Statement of Income. See Notes 1 and 2 of Notes to Condensed Consolidated Financial Statements for a further discussion.

Electric Competition; Regulation

OG&E and Enogex have been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although retail restructuring efforts in Oklahoma and Arkansas have been postponed for the time being, if such efforts were renewed, retail competition and the unbundling of regulated energy service could have a significant financial impact on the Company due to an impairment of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. Any such restructuring could have a significant impact on the Company's consolidated financial position, results of operations and cash flows. The Company cannot predict when it will be subject to changes in legislation or regulation, nor can it predict the impact of these changes on the Company's consolidated financial position, results of operations or cash flows. The Company believes that the prices for electricity and the quality and reliability of the Company's service currently place us in a position to compete effectively in the energy market. These developments at the federal and state levels are described in more detail in Notes 14 and 15 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, 2005.

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 legal counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Condensed Consolidated Financial Statements. Except as disclosed otherwise in this Form 10-Q and in the Company's Form 10-K for the year ended December 31, 2005 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 14 and 15 of Notes to Condensed Consolidated Financial Statements and Item 1 of Part II in this Form 10-Q and Notes 14 and 15 of Notes to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2005 for a discussion of the Company's commitments and contingencies.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Except as set forth below, the market risks set forth in Part II, Item 7A of the Company's Form 10-K for the year ended December 31, 2005 appropriately represent, in all material respects, the market risks affecting the Company.

Commodity Price Risk

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

Trading Activities

The trading activities are conducted throughout the year subject to daily and monthly trading stop loss limits of $2.5 million. The daily loss exposure from trading activities is measured primarily using value-at-risk ("VaR"), which estimates the potential losses the trading activities could incur over a specified time horizon and confidence level. The VaR limit for

the Company's trading activities, assuming a one day time horizon and 95 percent confidence level, is $1.5 million. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company's operating income.

A sensitivity analysis has been prepared to estimate the Company's exposure to market risk created by trading activities. The value of trading positions is a summation of the fair values calculated for each commodity by valuing each net position at quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in such prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows as of March 31, 2006.

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

Non-Trading Activities

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

A sensitivity analysis has been prepared to estimate the Company's exposure to the market risk of the Company's non-trading activities. The Company's daily net commodity position consists of natural gas inventories, commodity purchase and sales contracts, financial and commodity derivative instruments and anticipated natural gas processing spreads and fuel recoveries. Quoted market prices are not available for all of the Company's non-trading positions, therefore, the value of non-trading positions is a summation of the forecasted values calculated for each commodity based upon internally generated forecast prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in such prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows as of March 31, 2006.

(In millions)	Non-Trading
Commodity market risk, net	$ 8.4

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. In addition, the disclosure controls and procedures are designed to ensure that information required to be disclosed is accumulated and communicated to management, including the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the CEO and CFO, of the effectiveness of the Company's disclosure controls and procedures, the CEO and CFO have concluded that the Company's disclosure controls and procedures are effective.

No change in the Company's internal control over financial reporting has occurred during the Company's most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934).

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

Reference is made to Part I, Item 3 of the Company's Form 10-K for the year ended December 31, 2005 for a description of certain legal proceedings presently pending. Except as set forth below and in Notes 14 and 15 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q, there are no new significant cases to report against the Company or its subsidiaries and there have been no material changes in the previously reported proceedings.

1. As reported in Part I, Item 3 of the Company's Form 10-K for the year ended December 31, 2005, 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 against the individual shareholders of COOG and NGSC in the U.S. District Court for Western District of Oklahoma, the jury, in 2004, ruled in favor of the Company and Enogex for approximately $6.6 million ("Thrash Fraudulent Transfer Judgment"). In April 2005, the defendants filed an appeal in the Tenth Circuit Court of Appeals and on September 14, 2005, the defendants posted a cash bond for approximately $6.9 million to stay the execution of the Thrash Fraudulent Transfer Judgment pending appeal. On December 30, 2005, the parties reached a settlement of the Thrash Fraudulent Transfer Judgment and other COOG-related matters discussed in the Company's Form 10-K for the year ended December 31, 2005. On March 8, 2006, the individual defendants paid approximately $5.2 million (the "Settlement Amount") to the Company and Enogex. Thereafter, the parties dismissed the pending appeal of the Thrash Fraudulent Transfer Judgment to the Tenth Circuit. The Settlement Amount has been accounted for as a gain in the Company's Condensed Consolidated Financial Statements in the first quarter of 2006. The Company now considers these matters closed.

Item 1A. Risk Factors.

There have been no significant changes in the Company's risk factors as discussed in the Company's Form 10-K for the year ended December 31, 2005.

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

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

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
1/1/06 – 1/31/06	38,100	$ 27.08	N/A	N/A
2/1/06 – 2/28/06	26,900	$ 27.42	N/A	N/A
3/1/06 – 3/31/06	---	$ ---	N/A	N/A

N/A – not applicable

Item 6. Exhibits.

<u>Exhibit No.</u>	<u>Description</u>
1.01	Underwriting Agreement, dated January 4, 2006 between OG&E and J.P. Morgan Securities Inc. and Wachovia Capital Markets, LLC, on behalf of themselves and the other underwriters named therein relating to $110,000,000 in aggregate principal amount of the Company's 5.15% Senior Notes, Series due January 15, 2016 and $110,000,000 in aggregate principal amount of its 5.75% Senior Notes, Series due January 15, 2036 (collectively, the "Senior Notes"). (Filed as Exhibit 1.01 to OG&E's Form 8-K filed January 6, 2006 (File No. 1-1097) and incorporated by reference herein)
2.01	Asset purchase agreement dated March 30, 2006, by and between Enogex Gas Gathering, L.L.C. and Hiland Operating, Inc. (Filed as Exhibit 2.01 to the Company's Form 8-K filed April, 4, 2006 (File No. 1-12579) and incorporated by reference herein)

4.02	Supplemental Indenture No. 7 dated as of January 1, 2006 between OG&E and UMB Bank, N.A., as trustee, creating the Senior Notes. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed January 6, 2006 (File No. 1-1097) 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.

SIGNATURE

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

OGE ENERGY CORP.
(Registrant)

By /s/ Scott Forbes
Scott Forbes
Controller – Chief Accounting Officer

May 3, 2006

Exhibit 31.01

CERTIFICATIONS

I, Steven E. Moore, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: May 3, 2006

/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: May 3, 2006

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

Exhibit 32.01

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

In connection with the Quarterly Report of OGE Energy Corp. (the "Company") on Form 10-Q for the period ended March 31, 2006, as filed with the Securities and Exchange Commission (the "Report"), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

May 3, 2006

/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