OGE ENERGY CORP.
Form 10-Q
October 29, 2010

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

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2010

OR

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

Commission File Number: 1-12579

OGE ENERGY CORP.
(Exact name of registrant as specified in its charter)

Oklahoma (State or other jurisdiction of incorporation or organization)	73-1481638 (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 þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þ Yes o No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

At September 30, 2010, there were 97,476,755 shares of common stock, par value $0.01 per share, outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2010

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FORWARD-LOOKING STATEMENTS

Except for the historical statements contained herein, the matters discussed in this Form 10-Q, including those matters discussed in “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations,” are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words “anticipate”, “believe”, “estimate”, “expect”, “inten “objective”, “plan”, “possible”, “potential”, “project” and similar expressions. Actual results may vary materially from tho expressed in forward-looking statements. In addition to the specific risk factors discussed in “Item 1A. Risk Factors” in OGE Energy Corp.’s Annual Report on Form 10-K for the year ended December 31, 2009 (“2009 Form 10-K”) and “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations” herein, factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- general economic conditions, including the availability of credit, access to existing lines of credit, access to the commercial paper markets, actions of rating agencies and their impact on capital expenditures;
- the ability of OGE Energy Corp. (collectively, with its subsidiaries, the “Company”) and its subsidiaries to access the capital markets and obtain financing on favorable terms;
- prices and availability of electricity, coal, natural gas and natural gas liquids, each on a stand-alone basis and in relation to each other;
- business conditions in the energy and natural gas midstream industries;
- competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company;
- unusual weather;
- availability and prices of raw materials for current and future construction projects;
- Federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company’s markets;
- environmental laws and regulations that may impact the Company’s operations;
- changes in accounting standards, rules or guidelines;
- the discontinuance of accounting principles for certain types of rate-regulated activities;
- 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;
- the risk that the proposed transaction with Bronco Midstream Holdings LLC will not be completed, or will not be completed on the terms currently contemplated; and
- other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission including those listed in “Item 1A. Risk Factors” and in Exhibit 99.01 to the Company’s 2009 Form 10-K.

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

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

(In millions, except per share data)	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
OPERATING REVENUES				
Electric Utility operating revenues	$ 723.0	$ 577.9	$ 1,679.8	$ 1,339.9
Natural Gas Pipeline operating revenues	402.4	267.4	1,208.6	756.1
Total operating revenues	1,125.4	845.3	2,888.4	2,096.0
COST OF GOODS SOLD (exclusive of depreciation and amortization shown below)				
Electric Utility cost of goods sold	299.4	223.8	757.2	559.3
Natural Gas Pipeline cost of goods sold	313.2	190.3	932.0	532.2
Total cost of goods sold	612.6	414.1	1,689.2	1,091.5
Gross margin on revenues	512.8	431.2	1,199.2	1,004.5
OPERATING EXPENSES				
Other operation and maintenance	142.4	113.0	401.0	335.1
Depreciation and amortization	73.7	67.2	215.2	195.8
Taxes other than income	22.5	21.3	70.5	65.5
Total operating expenses	238.6	201.5	686.7	596.4
OPERATING INCOME	274.2	229.7	512.5	408.1
OTHER INCOME (EXPENSE)				
Interest income	---	0.3	---	1.4
Allowance for equity funds used during construction	2.6	5.5	7.2	10.7
Other income	0.6	7.0	5.8	20.0
Other expense	(2.7)	(3.9)	(8.8)	(8.9)
Net other income	0.5	8.9	4.2	23.2
INTEREST EXPENSE				
Interest on long-term debt	36.3	37.3	103.3	100.6
Allowance for borrowed funds used during construction	(1.3)	(2.9)	(3.5)	(5.9)
Interest on short-term debt and other interest charges	1.4	2.3	4.7	6.4
Interest expense	36.4	36.7	104.5	101.1
INCOME BEFORE TAXES	238.3	201.9	412.2	330.2
INCOME TAX EXPENSE	74.8	64.4	145.6	104.2
NET INCOME	163.5	137.5	266.6	226.0
Less: Net income attributable to noncontrolling interest	0.4	0.7	2.0	1.9
NET INCOME ATTRIBUTABLE TO OGE ENERGY	$ 163.1	$ 136.8	$ 264.6	$ 224.1
BASIC AVERAGE COMMON SHARES OUTSTANDING	97.4	96.7	97.3	96.0
DILUTED AVERAGE COMMON SHARES OUTSTANDING	99.0	97.7	98.8	96.9
BASIC EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	$ 1.67	$ 1.42	$ 2.72	$ 2.34

DILUTED EARNINGS PER AVERAGE COMMON SHARE				
ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	$ 1.65	$ 1.40	$ 2.68	$ 2.31
DIVIDENDS DECLARED PER COMMON SHARE	$ 0.3625	$ 0.3550	$ 1.0875	$ 1.0650

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

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

(In millions)	Nine Months Ended September 30, 2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 266.6	$ 226.0
Adjustments to reconcile net income to net cash provided from operating activities		
Depreciation and amortization	215.2	195.8
Deferred income taxes and investment tax credits, net	146.8	132.3
Allowance for equity funds used during construction	(7.2)	(10.7)
Stock-based compensation expense	4.9	2.5
Excess tax benefit on stock-based compensation	(0.7)	(3.3)
Price risk management assets	2.3	6.6
Price risk management liabilities	6.2	(67.7)
Regulatory assets	7.4	13.4
Regulatory liabilities	(10.7)	(12.4)
Other assets	14.3	(0.8)
Other liabilities	(10.5)	(42.2)
Change in certain current assets and liabilities		
Accounts receivable, net	(48.0)	2.8
Accrued unbilled revenues	(11.2)	(12.5)
Income taxes receivable	141.2	(40.5)
Fuel, materials and supplies inventories	(12.3)	(26.1)
Gas imbalance assets	---	(1.8)
Fuel clause under recoveries	(0.6)	23.7
Other current assets	7.8	6.8
Accounts payable	(13.7)	(105.0)
Gas imbalance liabilities	(1.0)	(15.2)
Fuel clause over recoveries	(119.5)	167.8
Other current liabilities	9.6	(0.2)
Net Cash Provided from Operating Activities	586.9	439.3
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures (less allowance for equity funds used during construction)	(591.3)	(689.1)
Construction reimbursement	3.3	32.9
Proceeds from sale of assets	1.9	0.8
Other investing activities	0.1	---
Net Cash Used in Investing Activities	(586.0)	(655.4)
CASH FLOWS FROM FINANCING ACTIVITIES		
Retirement of long-term debt	(289.2)	(110.8)
Dividends paid on common stock	(105.7)	(101.8)
Repayment of line of credit	(80.0)	(110.0)
Excess tax benefit on stock-based compensation	0.7	3.3

Issuance of common stock	13.5	74.9
Increase in short-term debt	49.0	10.0
Proceeds from line of credit	115.0	80.0
Proceeds from long-term debt	246.2	198.4
Net Cash (Used in) Provided from Financing Activities	(50.5)	44.0
NET DECREASE IN CASH AND CASH EQUIVALENTS	(49.6)	(172.1)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	58.1	174.4
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 8.5	$ 2.3

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

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2010 (Unaudited)	December 31, 2009
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 8.5	$ 58.1
Accounts receivable, less reserve of $2.2 and $2.4, respectively	339.4	291.4
Accrued unbilled revenues	68.4	57.2
Income taxes receivable	16.5	157.7
Fuel inventories	126.3	118.5
Materials and supplies, at average cost	82.9	78.4
Price risk management	3.4	1.8
Gas imbalances	3.2	3.2
Deferred income taxes	48.7	39.8
Fuel clause under recoveries	0.9	0.3
Other	10.9	19.7
Total current assets	709.1	826.1
OTHER PROPERTY AND INVESTMENTS, at cost	42.0	43.7
PROPERTY, PLANT AND EQUIPMENT		
In service	9,039.8	8,617.8
Construction work in progress	405.5	335.4
Total property, plant and equipment	9,445.3	8,953.2
Less accumulated depreciation	3,157.7	3,041.6
Net property, plant and equipment	6,287.6	5,911.6
DEFERRED CHARGES AND OTHER ASSETS		
Regulatory assets	454.3	448.9
Price risk management	0.4	4.3
Other	34.0	32.1
Total deferred charges and other assets	488.7	485.3
TOTAL ASSETS	$ 7,527.4	$ 7,266.7

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

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(In millions)	September 30, 2010 (Unaudited)	December 31, 2009
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 224.0	$ 175.0
Long-term debt due within one year	---	289.2
Accounts payable	266.2	297.0
Dividends payable	35.3	35.1
Customer deposits	67.0	85.6
Accrued taxes	57.2	37.0
Accrued interest	30.2	60.6
Accrued compensation	46.1	50.1
Price risk management	13.9	14.2
Gas imbalances	11.0	12.0
Fuel clause over recoveries	68.0	187.5
Other	53.1	32.4
Total current liabilities	872.0	1,275.7
LONG-TERM DEBT	2,372.8	2,088.9
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	331.2	369.3
Deferred income taxes	1,422.4	1,246.6
Deferred investment tax credits	10.3	13.1
Regulatory liabilities	185.1	168.2
Price risk management	1.8	0.1
Deferred revenues	37.2	---
Other	46.3	44.0
Total deferred credits and other liabilities	2,034.3	1,841.3
Total liabilities	5,279.1	5,205.9
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	908.7	887.7
Retained earnings	1,386.5	1,227.8
Accumulated other comprehensive loss, net of tax	(68.9)	(74.7)
Total OGE Energy stockholders' equity	2,226.3	2,040.8
Noncontrolling interest	22.0	20.0
Total stockholders' equity	2,248.3	2,060.8
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 7,527.4	$ 7,266.7

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

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Premium on Capital Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance at December 31, 2009	$ 1.0	$ 886.7	$ 1,227.8	$ (74.7)	$ 20.0	$ 2,060.8
Comprehensive income						
Net income	---	---	264.6	---	2.0	266.6
Other comprehensive income, net of tax	---	---	---	5.8	---	5.8
Comprehensive income	---	---	264.6	5.8	2.0	272.4
Dividends declared on common stock	---	---	(105.9)	---	---	(105.9)
Issuance of common stock	---	21.0	---	---	---	21.0
Balance at September 30, 2010	$ 1.0	$ 907.7	$ 1,386.5	$ (68.9)	$ 22.0	$ 2,248.3
Balance at December 31, 2008	$ 0.9	$ 802.0	$ 1,107.6	$ (13.7)	$ 17.2	$ 1,914.0
Comprehensive income (loss)						
Net income	---	---	224.1	---	1.9	226.0
Other comprehensive loss, net of tax	---	---	---	(43.5)	---	(43.5)
Comprehensive income (loss)	---	---	224.1	(43.5)	1.9	182.5
Dividends declared on common stock	---	---	(103.0)	---	---	(103.0)
Issuance of common stock	0.1	77.7	---	---	---	77.8
Balance at September 30, 2009	$ 1.0	$ 879.7	$ 1,228.7	$ (57.2)	$ 19.1	$ 2,071.3

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

(In millions)	Three Months Ended September 30, 2010	2009	Nine Months Ended September 30, 2010	2009
Net income	$ 163.5	$ 137.5	$ 266.6	$ 226.0
Other comprehensive income (loss), net of tax				
Defined benefit pension plan and restoration of retirement income plan:				
	0.6	0.8	1.6	2.3

Amortization of deferred net loss, net of tax of $0.4 million, $0.5 million, $1.4 million and $1.6 million, respectively				
Amortization of prior service cost, net of tax of $0.1 million, $0, $0.1 million and $0.1 million, respectively	0.1	---	0.2	0.1
Defined benefit postretirement plans:				
Amortization of deferred net loss, net of tax of $0.2 million, $0.1 million, $0.2 million and $0.2 million, respectively	0.3	0.2	1.2	0.3
Amortization of deferred net transition obligation, net of tax of $0, $0.1 million, $0.1 million and $0.1 million, respectively	---	0.1	0.3	0.1
Amortization of prior service cost, net of tax of $0, $0, ($0.1) million and $0.1 million, respectively	---	---	(0.2)	0.1
Deferred commodity contracts hedging gains (losses), net of tax of ($4.5) million, $1.0 million, $1.7 million and ($29.5) million, respectively	(7.0)	1.5	2.6	(46.6)
Deferred hedging gains on interest rate swaps, net of tax of $0, $0, $0.1 million and $0.1 million, respectively	---	---	0.1	0.2
Other comprehensive income (loss), net of tax	(6.0)	2.6	5.8	(43.5)
Total comprehensive income	157.5	140.1	272.4	182.5
Less: Comprehensive income attributable to noncontrolling interest	(0.4)	(0.7)	(2.0)	(1.9)
Total comprehensive income attributable to OGE Energy	$ 157.1	$ 139.4	$ 270.4	$ 180.6

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. ("OGE Energy" and 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 four business segments: (i) electric utility, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. 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. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

Enogex LLC and its subsidiaries ("Enogex") are providers of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream LLC joint venture ("Atoka") through Enogex Atoka LLC, a wholly-owned subsidiary of Enogex Gathering & Processing LLC. The Company has consolidated 100 percent of Atoka in its consolidated financial statements as Enogex acts as the managing member of Atoka and has control over the operations of Atoka. Enogex is a Delaware single-member limited liability company.

On October 5, 2010, OGE Energy entered into an Investment Agreement with Bronco Midstream Holdings LLC ("Bronco"), a subsidiary of ArcLight Energy Partners Fund IV, L.P. ("ArcLight"), and Enogex Holdings LLC, an indirect wholly-owned subsidiary of OGE Energy ("Enogex Holdings") pursuant to which Bronco agreed to make an initial equity investment in Enogex Holdings, the parent company of Enogex, in exchange for a 9.9 percent membership interest in Enogex Holdings. Prior to the closing of the transaction (which is expected to occur on November 1, 2010), 100 percent of the equity of OGE Energy Resources, Inc. ("OERI"), a natural gas marketing subsidiary currently owned by OGE Energy, will be contributed to Enogex.

The Company charges operating costs to its subsidiaries based on several factors. Operating costs directly related to specific subsidiaries are assigned to those subsidiaries. Where more than one subsidiary benefits from certain expenditures, the costs are shared between those subsidiaries receiving the benefits. Operating costs incurred for the benefit of all subsidiaries are allocated among the subsidiaries, either as overhead based primarily on labor costs or using 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 generally accepted accounting principles ("GAAP") have been condensed or omitted pursuant to such rules and regulations; however, the Company believes that the disclosures are adequate to prevent the information presented from being misleading.

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at September 30, 2010 and December 31, 2009, the results of its operations for the three and nine months ended

September 30, 2010 and 2009 and the results of its cash flows for the nine months ended September 30, 2010 and 2009, have been included and are of a normal recurring nature except as otherwise disclosed.

Due to seasonal fluctuations and other factors, the operating results for the three and nine months ended September 30, 2010 are not necessarily indicative of the results that may be expected for the year ending December 31, 2010 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 Annual Report on Form 10-K for the year ended December 31, 2009 ("2009 Form 10-K").

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 accounting principles for certain types of rate-regulated activities, which provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

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

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

(In millions)	September 30, 2010	December 31, 2009
Regulatory Assets		
Current		
Fuel clause under recoveries	$ 0.9	$ 0.3
Miscellaneous (A)	0.9	2.2
Total Current Regulatory Assets	$ 1.8	$ 2.5
Non-Current		
Benefit obligations regulatory asset	$ 333.0	$ 357.8
Income taxes recoverable from customers, net	41.1	19.1
Deferred storm expenses	30.0	28.0
Unamortized loss on reacquired debt	15.6	16.5
Deferred pension plan expenses	14.7	18.1
Smart Grid	10.6	---
Red Rock deferred expenses	7.4	7.7
Miscellaneous	1.9	1.7
Total Non-Current Regulatory Assets	$ 454.3	$ 448.9
Regulatory Liabilities		
Current		
Fuel clause over recoveries	$ 68.0	$ 187.5
Miscellaneous (B)	17.6	7.3
Total Current Regulatory Liabilities	$ 85.6	$ 194.8

Non-Current		
Accrued removal obligations, net	$ 179.3	$ 168.2
Miscellaneous	5.8	---
Total Non-Current Regulatory Liabilities	$ 185.1	$ 168.2

(A) Included in Other Current Assets on the Condensed Consolidated Balance Sheets.
(B) Included in Other Current Liabilities on the Condensed Consolidated Balance Sheets.

For a discussion of regulatory assets related to OG&E's Smart Grid program, see Note 14.

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 adjusted, as appropriate. If the Company were required to discontinue the application of accounting principles for certain types of rate-regulated activities 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.

Deferred Revenues

The Company records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP.

In January 2009, Enogex entered into a Facility Construction, Ownership and Operating Agreement for the installation of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Construction of the required facilities was completed during August 2010. Aid in Construction payments of $37.2 million received in excess of construction costs have been recognized as Deferred Revenues on the Company's Condensed Consolidated Balance Sheet and will be amortized on a straight-line basis of $1.2 million per year over the life of the related Intrastate Firm Transportation Services agreement under which service will commence in June 2011.

Reclassifications

Certain prior year amounts have been reclassified on the Condensed Consolidated Statements of Income and Condensed Consolidated Balance Sheet to conform to the 2010 presentation primarily related to the presentation of regulatory assets and liabilities. Certain prior year amounts have been reclassified on the Condensed Consolidated Statement of Cash Flows to conform to the 2010 presentation related to a customer's reimbursement of Enogex's costs related to the construction of a transportation pipeline in 2009 and 2010 as well as a change in the presentation of regulatory assets and liabilities.

2. Investment Agreement with ArcLight

On October 5, 2010, OGE Energy entered into an Investment Agreement with Bronco and Enogex Holdings pursuant to which Bronco agreed to make an initial equity investment in Enogex Holdings, the parent company of Enogex, in an amount equal to $183,150,000 in exchange for a 9.9 percent membership interest in Enogex Holdings. This transaction will be accounted for as an equity transaction for entities under common control and no gain or loss will be recognized in the Company's Condensed Consolidated Financial Statements. OGE Energy will continue to consolidate 100 percent of Enogex in its consolidated financial statements as OGE Energy has a controlling financial interest over the operations of Enogex. Bronco's ownership interest will be presented as a noncontrolling interest in the Company's Condensed Consolidated Financial Statements. Prior to the closing of the transaction, 100 percent of the equity of OERI, which is currently owned by OGE Energy, will be contributed to Enogex.

Consummation of the transaction is conditioned on certain customary closing conditions. However, no regulatory approvals are required to close the transaction. Pending closing of the transaction, which is anticipated to occur on November 1, 2010, the Company has agreed to customary interim operating covenants relating to the conduct of Enogex's business. If the transaction closes, the Company and Bronco have agreed to indemnify each other for breaches of representations, warranties and covenants contained in the Investment Agreement, and, in the case of the Company, for certain tax matters related to the Company, in each case subject to customary thresholds and survival periods.

Upon consummation of the transactions contemplated by the Investment Agreement, OGE Enogex Holdings LLC, a wholly-owned subsidiary of the Company and the parent of Enogex Holdings ("OGE Holdings"), and Bronco will enter into an Amended and Restated Limited Liability Company Agreement of Enogex Holdings ("LLC Agreement").

Pursuant to the LLC Agreement, OGE Holdings' and Bronco's rights to designate directors to the board of directors of Enogex Holdings ("Enogex Holdings Board") will be determined by percentage ownership. OGE Holdings will initially be entitled to designate three directors, and Bronco will initially be entitled to designate one director. Bronco will also be entitled, at various ownership thresholds, to certain special board approval rights with respect to certain significant actions taken by Enogex Holdings.

Until Bronco owns 50 percent of the equity of Enogex Holdings, Bronco will fund capital contributions in an amount higher than its proportionate interest. Specifically, Bronco will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings. Until the beginning of 2012, the per unit equity price to be paid will be equal to the price paid by Bronco under the Investment Agreement. On and after January 1, 2012, the equity price per unit will be based on the equity value of Enogex Holdings. Subject to certain adjustments, including for material acquisitions, equity value will be calculated as 9.0 or 9.5 times trailing twelve-month Earnings before Interest, Income Taxes and Depreciation and Amortization, depending on Bronco's ownership interest and whether the project has already been identified by Enogex.

Pursuant to the LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover the members' respective anticipated tax liabilities plus $12,500,000, to be distributed in proportion to each member's percentage ownership interest.

Under the terms of the LLC Agreement, each member and its affiliates are prohibited from independently pursuing a transaction in which a portion of the relevant assets are located in a designated core operating area ("Core Operating Area"), subject to certain exceptions. In addition, each member and its affiliates are prohibited from independently pursuing a transaction in which a portion of the relevant assets are located in a designated "area of mutual interest" ("AMI") unless (i) in the case of Bronco, its ownership interest is less than 5 percent, (ii) the transaction falls within a defined category of passive financial investments, (iii) the proposed transaction has been disapproved by Enogex Holdings or (iv) the fair market value of the assets located in the AMI constitutes less than 50 percent of the total fair market value of the assets involved in the transaction. A member permitted to pursue a transaction independently pursuant to the foregoing is not required to offer the assets associated with such transaction to Enogex Holdings.

3. Fair Value Measurements

The classification of the Company's fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. GAAP establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to quoted prices in active markets for identical unrestricted assets or liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible at the measurement date. An example of instruments that may be classified as Level 1 are futures transactions for energy commodities traded on the New York Mercantile Exchange ("NYMEX").

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. An example of instruments that may be classified as Level 2 includes energy commodity purchase or sales transactions in a market such that the pricing is closely related to the NYMEX pricing.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk). An example of instruments that may be classified as Level 3 includes energy commodity purchase or sales transactions of a longer duration or in an inactive market such that there are no closely related markets in which quoted prices are available.

The Company utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. Otherwise, they are considered Level 3.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services ("Standard & Poor's") and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate 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, 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 Condensed Consolidated Balance Sheets. The Company has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize the Company's assets and liabilities that are measured at fair value on a recurring basis at September 30, 2010 and December 31, 2009 as well as reconcile the Company's commodity contracts fair value to Price Risk Management ("PRM") Assets and Liabilities on the Company's Condensed Consolidated Balance Sheet at September 30, 2010 and December 31, 2009.

	September 30, 2010			
(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets	Liabilities (B)
Quoted market prices in active market for identical assets (Level 1)	$ 35.9	$ 34.3	$ ---	$ ---
Significant other observable inputs (Level 2)	6.9	42.9	3.2	3.2
Significant unobservable inputs (Level 3)	26.9	3.2	---	---
Total fair value	69.7	80.4	3.2	3.2
Netting adjustments	(65.9)	(64.7)	---	---
Total	$ 3.8	$ 15.7	$ 3.2	$ 3.2

	December 31, 2009			
(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets	Liabilities (B)
Quoted market prices in active market for identical assets (Level 1)	$ 16.1	$ 13.3	$ ---	$ ---
Significant other observable inputs (Level 2)	6.2	49.8	3.2	8.0
Significant unobservable inputs (Level 3)	49.0	14.7	---	---
Total fair value	71.3	77.8	3.2	8.0
Netting adjustments	(65.2)	(63.5)	---	---
Total	$ 6.1	$ 14.3	$ 3.2	$ 8.0

(A) The Company uses the market approach to fair value its gas imbalance assets and liabilities, using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices.
(B) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $7.8 million and $4.0 million at September 30, 2010 and December 31, 2009, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

The following table summarizes the Company's assets and liabilities that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

	Commodity Contracts			
	Assets		Liabilities	
(In millions)	2010	2009	2010	2009
Balance at January 1	$ 49.0	$ 121.2	$ 14.7	$ ---
Total gains or losses				
Included in other comprehensive income	(3.9)	(11.1)	(5.1)	---
Purchases, issuances, sales and settlements				
Settlements	(4.1)	(4.5)	(1.4)	---
Balance at March 31	41.0	105.6	8.2	---
Total gains or losses				
Included in other comprehensive income	7.2	(34.4)	(3.7)	---
Purchases, issuances, sales and settlements				
Purchases	---	---	---	1.8
Settlements	(6.1)	(3.9)	(2.7)	---
Balance at June 30	42.1	67.3	1.8	1.8
Total gains or losses				
Included in other comprehensive income	(8.5)	(2.5)	2.3	(0.4)
Purchases, issuances, sales and settlements				
Settlements	(6.7)	(1.4)	(0.9)	---
Balance at September 30	$ 26.9	$ 63.4	$ 3.2	$ 1.4
Amount of total gains or losses included in earnings attributable to the change in unrealized gains or losses relating to assets and liabilities held at September 30	$ ---	$ ---	$ ---	$ ---

Gains and losses (realized and unrealized) included in earnings for the three and nine months ended September 30, 2010 and 2009 attributable to the change in unrealized gains or losses relating to assets and liabilities held at September 30, 2010 and 2009, if any, are reported in Operating Revenues.

The following table summarizes the fair value and carrying amount of the Company's financial instruments, including derivative contracts related to the Company's PRM activities at September 30, 2010 and December 31, 2009.

	September 30, 2010		December 31, 2009	
(In millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Derivative Contracts	$ 3.8	$ 3.8	$ 6.1	$ 6.1
Price Risk Management Liabilities				
Energy Derivative Contracts	$ 15.7	$ 15.7	$ 14.3	$ 14.3
Long-Term Debt				
OG&E Senior Notes	$ 1,655.0	$ 1,958.1	$ 1,406.4	$ 1,492.1

OGE Energy Senior Notes	99.6	109.6	99.5	102.6
OG&E Industrial Authority Bonds	135.4	135.4	135.4	135.4
Enogex Senior Notes	447.8	499.7	736.8	746.7
Enogex Revolving Credit Agreement	35.0	35.0	---	---

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 derivative contracts was determined generally 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. The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities.

4. Derivative Instruments and Hedging Activities

The Company is exposed to certain risks relating to its ongoing business operations. The primary risks managed using derivatives instruments are commodity price risk and interest rate risk. The Company is also exposed to credit risk in its business operations.

Commodity Price Risk

The Company primarily uses forward physical contracts, commodity price swap contracts and commodity price option features to manage the Company's commodity price risk exposures. Commodity derivative instruments used by the Company are as follows:

- Ÿnatural gas liquids ("NGL") put options and NGLs swaps are used to manage Enogex's NGLs exposure associated with its processing agreements;
- Ÿnatural gas swaps are used to manage Enogex's keep-whole natural gas exposure associated with its processing operations and Enogex's natural gas exposure associated with operating its gathering, transportation and storage assets;
- Ÿnatural gas futures and swaps and natural gas commodity purchases and sales are used to manage OERI's natural gas exposure associated with its storage and transportation contracts; and
- Ÿ natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage OERI's marketing and trading activities.

Normal purchases and normal sales contracts are not recorded in PRM Assets or Liabilities in the Condensed Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by its operations, (ii) commodity contracts for the sale of NGLs produced by Enogex's gathering and processing business, (iii) electric power contracts by OG&E and (iv) fuel procurement by OG&E.

The Company recognizes its non-exchange traded derivative instruments as PRM Assets or Liabilities in the Condensed Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Condensed Consolidated Balance Sheets.

Interest Rate Risk

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

Credit Risk

The Company is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Company money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Company may be forced to enter into alternative arrangements. In that event, the Company's financial results could be adversely affected and the Company could incur losses.

Cash Flow Hedges

For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative’s change in fair value or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. The Company measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. Forecasted transactions, which are designated as the hedged transaction in a cash flow hedge, are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings.

The Company designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing, pipeline and storage operations (operational gas hedges). Enogex's cash flow hedging activity at September 30, 2010 covers the period from October 1, 2010 through December 31, 2011. The Company also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions at OERI. OERI's cash flow hedging activity extends through February 28, 2011.

Fair Value Hedges

For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedge risk are recognized currently in earnings. The Company includes the gain or loss on the hedged items in Operating Revenues as the offsetting loss or gain on the related hedging derivative.

At September 30, 2010 and December 31, 2009, the Company had no derivative instruments that were designated as fair value hedges.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments are utilized in OERI's asset management, marketing and trading activities and also include contracts formerly designated as cash flow hedges of Enogex's NGLs, keep-whole natural gas and operational storage natural gas exposures. A portion of Enogex's processing agreements, which were previously under keep-whole arrangements, were converted to fee-based arrangements. As a result, effective June 30, 2009 Enogex de-designated a portion of these derivatives and entered into offsetting derivatives to close the positions. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

At September 30, 2010, the Company had the following derivative instruments that were designated as cash flow hedges.

(In millions)	Gross Notional Volume (A)	
	2010	2011
Enogex processing hedges		
NGLs sales	0.4	1.3
Natural gas purchases	1.6	5.2
Enogex operational gas hedges		
Natural gas sales	0.5	---
OERI hedges		
Natural gas sales	---	0.9

(A) Natural gas in million British thermal unit ("MMBtu"); NGLs in barrels.

At September 30, 2010, the Company had the following derivative instruments that were not designated as hedging instruments.

(In millions)	Gross Notional Volume (A)	
	Purchases	Sales
Natural Gas (B)		
Physical (C)(D)	20.1	59.1
Fixed Swaps/Futures	44.8	44.7
Options	26.3	24.1
Basis Swaps	16.4	12.7
NGLs (B)		
Fixed Swaps/Futures	0.2	0.2

(A) Natural gas in MMBtu; NGLs in barrels.
(B) 88 percent of the natural gas contracts have durations of one year or less, seven percent have durations of more than one year and less than two years and five percent have durations of more than two years. The NGLs contracts all settle by December 31, 2010.
(C) Of the natural gas physical purchases and sales volumes not designated as hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.
(D) Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via Enogex's processing contracts, which are not derivative instruments and are excluded from the table above.

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Company's Condensed Consolidated Balance Sheet at September 30, 2010 are as follows:

		Fair Value	
Instrument	Balance Sheet Location	Assets	Liabilities
		(In millions)	
Derivatives Designated as Hedging Instruments			
NGLs			
Financial Options	Current PRM	$ 19.7	$ ---
	Non-Current PRM	5.3	---
Financial Futures/Swaps	Current PRM	---	1.3
Natural Gas			
Financial Futures/Swaps	Current PRM	---	29.2
	Non-Current PRM	---	7.0
	Other Current Assets	2.4	0.1
Total		$ 27.4	$ 37.6
Derivatives Not Designated as Hedging Instruments			
NGLs			
Financial Futures/Swaps (A)	Current PRM	$ 2.0	$ 1.9
Natural Gas			
Financial Futures/Swaps (B)	Current PRM	2.2	4.4
	Other Current Assets	33.7	34.5
Physical Purchases/Sales	Current PRM	3.1	0.7
	Non-Current PRM	0.4	0.1
Financial Options	Other Current Assets	0.9	1.2
Total		$ 42.3	$ 42.8
Total Gross Derivatives (C)		$ 69.7	$ 80.4

(A) The entire fair value of Financial Futures/Swaps – NGLs not designated as hedging instruments consists of derivatives that were previously designated as hedging instruments and subsequently de-designated with offsetting derivatives to close the hedge positions.

(B) The fair value of Financial Futures/Swaps – Natural Gas not designated as hedging instruments includes derivatives that were previously designated as hedging instruments and subsequently de-designated with offsetting derivatives to close the hedge positions. The referenced derivatives had a fair value as presented in the table above in Current Assets of $1.8 million and Current Liabilities of $4.2 million.

(C) See reconciliation of the Company's total derivatives fair value to the Company's Condensed Consolidated Balance Sheet at September 30, 2010 (see Note 3).

The fair value of the derivative instruments that are presented in the Company's Condensed Consolidated Balance Sheet at December 31, 2009 are as follows:

Instrument	Balance Sheet Location	Fair Value Assets	Fair Value Liabilities
		(In millions)	
Derivatives Designated as Hedging Instruments			
NGLs			
Financial Options	Current PRM	$ 16.4	$ ---
	Non-Current PRM	23.4	---
Financial Futures/Swaps	Current PRM	---	6.1
Natural Gas			
Financial Futures/Swaps	Current PRM	---	14.8
	Non-Current PRM	---	19.7
	Other Current Assets	4.6	1.2
Total		$ 44.4	$ 41.8
Derivatives Not Designated as Hedging Instruments			
NGLs			
Financial Futures/Swaps (A)	Current PRM	$ 9.2	$ 8.6
Natural Gas			
Financial Futures/Swaps (B)	Current PRM	3.6	12.3
	Non-Current PRM	---	0.1
	Other Current Assets	11.8	13.6
Physical Purchases/Sales	Current PRM	0.8	0.6
	Non-Current PRM	0.6	---
Financial Options	Other Current Assets	0.9	0.8
Total		$ 26.9	$ 36.0
Total Gross Derivatives (C)		$ 71.3	$ 77.8

(A) The entire fair value of Financial Futures/Swaps – NGLs not designated as hedging instruments consists of derivatives that were previously designated as hedging instruments and subsequently de-designated with offsetting derivatives to close the hedge positions.

(B) The fair value of Financial Futures/Swaps – Natural Gas not designated as hedging instruments includes derivatives that were previously designated as hedging instruments and subsequently de-designated with offsetting derivatives to close the hedge positions. The referenced derivatives had a fair value as presented in the table above in Current Assets of $2.9 million and Current Liabilities of $11.7 million.

(C) See reconciliation of the Company's total derivatives fair value to the Company's Condensed Consolidated Balance Sheet at December 31, 2009 (see Note 3).

Income Statement Presentation Related to Derivative Instruments

The following table presents the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the three months ended September 30, 2010.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in OCI (A)	Amount Reclassified from Accumulated OCI into Income	Amount Recognized in Income
NGLs Financial Options	$ (12.2)	$ 1.5	$ ---
NGLs Financial Futures/Swaps	(1.2)	(0.3)	---
Natural Gas Financial Futures/Swaps	(5.5)	(6.7)	---
Total	$ (18.9)	$ (5.5)	$ ---

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at September 30, 2010 that is expected to be reclassified into income within the next 12 months is a loss of $14.5 million.

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$ (2.3)
Natural Gas Financial Futures/Swaps	0.6
Total	$ (1.7)

The following table presents the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the three months ended September 30, 2009.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in OCI	Amount Reclassified from Accumulated OCI into Income	Amount Recognized in Income
NGLs Financial Options	$ (2.7)	$ 0.3	$ ---
NGLs Financial Futures/Swaps	(0.8)	2.2	---
Natural Gas Financial Futures/Swaps	---	(8.3)	0.1
Total	$ (3.5)	$ (5.8)	$ 0.1

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income

Natural Gas Physical Purchases/Sales	$	(8.3)
Natural Gas Financial Futures/Swaps		4.3
Total	$	(4.0)

The following table presents the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the nine months ended September 30, 2010.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in OCI (A)	Amount Reclassified from Accumulated OCI into Income	Amount Recognized in Income
NGLs Financial Options	$ (1.2)	$ 2.0	$ ---
NGLs Financial Futures/Swaps	2.1	(2.2)	---
Natural Gas Financial Futures/Swaps	(15.4)	(18.7)	0.1
Total	$ (14.5)	$ (18.9)	$ 0.1

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at September 30, 2010 that is expected to be reclassified into income within the next 12 months is a loss of $14.5 million.

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$ (6.4)
Natural Gas Financial Futures/Swaps	0.8
Total	$ (5.6)

The following table presents the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the nine months ended September 30, 2009.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in OCI	Amount Reclassified from Accumulated OCI into Income	Amount Recognized in Income
NGLs Financial Options	$ (36.6)	$ 3.2	$ ---
NGLs Financial Futures/Swaps	(26.0)	12.4	---
Natural Gas Financial Futures/Swaps	(17.0)	(19.4)	(0.2)
Total	$ (79.6)	$ (3.8)	$ (0.2)

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income

Natural Gas Physical Purchases/Sales	$	(18.8)
Natural Gas Financial Futures/Swaps		12.7
NGLs Financial Futures/Swaps		(0.2)
Total	$	(6.3)

For derivatives designated as cash flow hedges in the tables above, amounts reclassified from Accumulated Other Comprehensive Income into income (effective portion) and amounts recognized in income (ineffective portion) for the three and nine months ended September 30, 2010 and 2009, if any, are reported in Operating Revenues. For derivatives not designated as hedges in the tables above, amounts recognized in income for the three and nine months ended September 30, 2010 and 2009, if any, are reported in Operating Revenues.

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Service or Standard & Poor's were to lower the Company's senior unsecured debt rating to a below investment grade rating, at September 30, 2010, the Company would have been required to post $13.7 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at September 30, 2010. In addition, the Company could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

5. Stock-Based Compensation

The Company recorded compensation expense of $2.6 million pre-tax ($1.6 million after tax, or $0.02 per basic and diluted share) and $6.5 million pre-tax ($4.0 million after tax, or $0.04 per basic and diluted share), respectively, during the three and nine months ended September 30, 2010 related to the Company's performance units. The Company recorded compensation expense of $1.6 million pre-tax ($1.0 million after tax, or $0.01 per basic and diluted share) and $4.9 million pre-tax ($3.0 million after tax, or $0.03 per basic and diluted share), respectively, during the three and nine months ended September 30, 2009 related to the Company's performance units.

The Company issues new shares to satisfy stock option exercises and payouts of earned performance units. During the three and nine months ended September 30, 2010, there were 22,900 shares and 218,033 shares, respectively, of new common stock issued pursuant to the Company's compensation plans related to exercised stock options and payouts of earned performance units. The Company received $0.5 million and $2.1 million, respectively, during the three months ended September 30, 2010 and 2009, and $3.0 million and $2.1 million, respectively, during the nine months ended September 30, 2010 and 2009, related to exercised stock options.

There was no restricted stock awarded during the three months ended September 30, 2010. The Company awarded 23,775 shares of restricted stock during the nine months ended September 30, 2010. There were 1,684 shares of restricted stock forfeited during both the three and nine months ended September 30, 2010.

6. Accumulated Other Comprehensive Income (Loss)

The following table summarizes the components of accumulated other comprehensive loss at September 30, 2010 and December 31, 2009 attributable to OGE Energy. At both September 30, 2010 and December 31, 2009, there was no accumulated other comprehensive loss related to Enogex's noncontrolling interest in Atoka.

(In millions)	September 30, 2010	December 31, 2009
Defined benefit pension plan and restoration of retirement income plan:		
Net loss	$(38.4)	$(40.0)
Prior service cost	(0.5)	(0.7)
Defined benefit postretirement plans:		
Net loss	(9.5)	(10.7)
Net transition obligation	(0.1)	(0.4)
Prior service cost	(0.2)	---
Deferred commodity contacts hedging losses	(19.1)	(21.7)
Deferred hedging losses on interest rate swaps	(1.1)	(1.2)
Total accumulated other comprehensive loss	$(68.9)	$(74.7)

7. Income Taxes

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal tax examinations by tax authorities for years prior to 2006 or state and local tax examinations by tax authorities for years prior to 2002. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed 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. OG&E earns both Federal and Oklahoma state tax credits associated with the production from its wind farms. In addition, OG&E and Enogex earn Oklahoma state tax credits associated with their investments in electric generating and natural gas processing facilities which further reduce the Company's effective tax rate.

The Company had a Federal tax net operating loss for 2009 primarily caused by the accelerated tax depreciation provisions contained within the American Recovery and Reinvestment Act of 2009 ("ARRA"). ARRA allowed a current deduction for 50 percent of the cost of certain property placed into service during 2009. This tax loss resulted in a $68 million current income tax receivable related to the 2009 tax year. On November 6, 2009, the Worker, Homeownership, and Business Assistance Act of 2009 was signed into law by the President. This new law provided for a five-year carry back of net operating losses incurred in 2008 or 2009. This expanded carryback period enabled the Company to carry back the entire 2009 tax loss. A carryback claim was filed in March 2010 and a refund of $68 million was received by the Company in April 2010.

In June 2010, new legislation was passed in Oklahoma that created a moratorium, from July 1, 2010 through June 30, 2012, on 30 income tax credits. For income tax purposes, credits affected by the moratorium may not be claimed for any event, transaction, investment, expenditure or other act for which the credits would otherwise be allowable. During this two-year window, affected credits generated by the Company will be deferred and utilized at a time after the moratorium expires. For financial accounting purposes, the Company will receive the benefits in the future as the credits do not expire if they are not utilized in the period they are generated.

In September 2010, the Small Business Jobs and Credit Act of 2010 was signed into law, which allows the Company to record a current income tax deduction for 50 percent of the cost of certain property placed into service during 2010 as a result of the accelerated tax depreciation provisions within the new law. As a result, for income tax purposes, the Company expects minimal Federal taxable income for 2010. For financial accounting purposes, the Company recorded an increase in its Non-Current Deferred Income Taxes Liability at September 30, 2010 on the Company's Condensed Consolidated Balance Sheet to recognize the financial statement impact of this new law.

Medicare Part D Subsidy

On March 23, 2010, the Patient Protection and Affordable Care Act of 2009 (the "Patient Protection Act") was signed into law, and, on March 30, 2010, the Health Care and Education Reconciliation Act of 2010 (the "Reconciliation Act" and, together with Patient Protection Act, the "Acts"), which makes various amendments to certain aspects of the Patient Protection Act, was signed into law. The Acts effectively change the tax treatment of federal subsidies paid to sponsors of retiree health benefit plans that provide prescription drug benefits that are at least actuarially equivalent to the corresponding benefits provided under Medicare Part D.

The federal subsidy paid to employers was introduced as part of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the "Medicare Act"). The Company has been recognizing the federal subsidy since 2005 related to certain retiree prescription drug plans that were determined to be actuarially equivalent to the benefit provided under Medicare Part D. Under the Medicare Act, the federal subsidy does not reduce an employer's income tax deduction for the costs of providing such prescription drug plans nor is it subject to income tax individually.

Under the Acts, beginning in 2013 an employer's income tax deduction for the costs of providing Medicare Part D-equivalent prescription drug benefits to retirees will be reduced by the amount of the federal subsidy. Under GAAP, any impact from a change in tax law must be recognized in earnings in the period enacted regardless of the effective date. As retiree healthcare liabilities and related tax impacts are already reflected in the Company's Condensed Consolidated Financial Statements, the Company recognized a one-time, non-cash charge of $11.4 million, or $0.11 per diluted share, during the quarter ended March 31, 2010 for the write-off of previously recognized tax benefits relating to Medicare Part D subsidies to reflect the change in the tax treatment of the federal subsidy.

8. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

In November 2008, the Company filed a Form S-3 Registration Statement to register 5,000,000 shares of the Company's common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan ("DRIP/DSPP"). The Company issued 82,550 shares and 272,236 shares, respectively, of common stock under its DRIP/DSPP during the three and nine months ended September 30, 2010 and received proceeds of $3.3 million and $10.6 million, respectively. The Company may, from time to time, issue additional shares under its DRIP/DSPP to fund capital requirements or working capital needs.

At September 30, 2010, there were 2,720,508 shares of unissued common stock reserved for issuance under the Company's DRIP/DSPP.

Earnings Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010	2009	2010	2009
Average Common Shares Outstanding				
Basic average common shares outstanding	97.4	96.7	97.3	96.0
Effect of dilutive securities:				
Contingently issuable shares (performance units)	1.6	1.0	1.5	0.9
Diluted average common shares outstanding	99.0	97.7	98.8	96.9
Anti-dilutive shares excluded from EPS calculation	---	---	---	---

9. Long-Term Debt

At September 30, 2010, the Company was in compliance with all of its debt agreements.

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

SERIES	DATE DUE	AMOUNT (In millions)
0.30% - 0.50%	Garfield Industrial Authority, January 1, 2025	$ 47.0
0.35% - 0.52%	Muskogee Industrial Authority, January 1, 2025	32.4
0.33% - 0.55%	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, OG&E is obligated to repurchase such unremarketed Bonds. As OG&E has both the intent and ability to refinance the Bonds on a long-term basis and such ability is supported by an ability to consummate the refinancing, the Bonds are classified as long-term debt in the Company’s Condensed Consolidated Financial Statements. OG&E believes that it has sufficient liquidity to meet these obligations.

10. Short-Term Debt and Credit Facilities

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $224.0 million and $175.0 million at

September 30, 2010 and December 31, 2009, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at September 30, 2010.

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Revolving Credit Agreements and Available Cash

Entity	Aggregate Commitment	Amount Outstanding (A)	Weighted-Average Interest Rate	Maturity
	(In millions)			
OGE Energy (B)	$ 596.0	$ 224.0	0.37% (D)	December 6, 2012
OG&E (C)	389.0	9.5	0.14% (D)	December 6, 2012
Enogex (E)	250.0	35.0	0.57% (D)	March 31, 2013
	1,235.0	268.5	0.39%	
Cash	8.5	N/A	N/A	N/A
Total	$ 1,243.5	$ 268.5	0.39%	

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at September 30, 2010.
(B) This bank facility is available to back up OGE Energy's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At September 30, 2010, there were no outstanding borrowings under this revolving credit agreement and $224.0 million in outstanding commercial paper borrowings.
(C) This bank facility is available to back up OG&E's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At September 30, 2010, there was $9.5 million supporting letters of credit. There were no outstanding borrowings under this revolving credit agreement and no outstanding commercial paper borrowings at September 30, 2010.
(D) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit.
(E) This bank facility is available to provide revolving credit borrowings for Enogex. As Enogex's credit agreement matures on March 31, 2013, borrowings thereunder are classified as long-term debt in the Company's Condensed Consolidated Balance Sheets.

OGE Energy'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 Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade of the Company could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post cash collateral or letters of credit.

Unlike OGE Energy and Enogex, OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2009 and ending December 31, 2010.

11. Retirement Plans and Postretirement Benefit Plans

The details of net periodic benefit cost of the pension plan, 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			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010 (A)	2009 (A)	2010 (B)	2009 (B)

Service cost	$ 4.1	$ 4.6	$ 12.5	$ 13.6
Interest cost	8.0	7.8	23.9	23.5
Expected return on plan assets	(10.6)	(8.2)	(31.8)	(24.7)
Amortization of net loss	5.3	5.8	15.9	17.6
Amortization of unrecognized prior service cost	0.6	0.2	1.8	0.6
Net periodic benefit cost	$ 7.4	$ 10.2	$ 22.3	$ 30.6

	Restoration of Retirement Income Plan			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010 (A)	2009 (A)	2010 (B)	2009 (B)
Service cost	$ 0.3	$ 0.1	$ 0.7	$ 0.5
Interest cost	0.2	0.1	0.4	0.3
Amortization of net loss	---	0.1	0.2	0.2
Amortization of unrecognized prior service cost	0.1	0.2	0.5	0.5
Net periodic benefit cost	$ 0.6	$ 0.5	$ 1.8	$ 1.5

(A) In addition to the $8.0 million and $10.7 million of net periodic benefit cost recognized during the three months ended September 30, 2010 and 2009, respectively, the Company recognized the following:

Ÿ An increase in pension expense during the three months ended September 30, 2010 of $2.3 million and a reduction in pension expense of less than $0.1 million during the same period in 2009 to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction which are identified as Deferred Pension Plan Expenses (see Note 1).

(B) In addition to the $24.1 million and $32.1 million of net periodic benefit cost recognized during the nine months ended September 30, 2010 and 2009, respectively, the Company recognized the following:

Ÿ An increase in pension expense during the nine months ended September 30, 2010 of $5.8 million and a reduction in pension expense of $2.2 million during the same period in 2009 to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction which are identified as Deferred Pension Plan Expenses (see Note 1); and

Ÿ A reduction in pension expense during the nine months ended September 30, 2009 of $3.2 million in the Arkansas jurisdiction to reflect the approval of recovery of OG&E's 2006 and 2007 pension settlement costs in the May 2009 Arkansas rate order which are identified as Deferred Pension Plan Expenses (see Note 1).

	Postretirement Benefit Plans			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010	2009	2010	2009
Service cost	$ 1.1	$ 0.8	$ 3.2	$ 2.5
Interest cost	4.2	3.6	12.7	10.6
Expected return on plan assets	(1.7)	(1.6)	(5.2)	(4.9)
Amortization of transition obligation	0.7	0.7	2.1	2.1
Amortization of net loss	3.0	1.2	9.1	3.7
Amortization of unrecognized prior service cost	---	0.2	---	0.7
Net periodic benefit cost	$ 7.3	$ 4.9	$ 21.9	$ 14.7

Pension Plan Funding

In the third quarter of 2010, the Company contributed $10 million to its pension plan for a total contribution of $50 million to its pension plan during 2010. No additional contributions are expected in 2010.

12. Report of Business Segments

The Company's business is divided into four segments for financial reporting purposes. These segments are as follows: (i) electric utility, which is engaged in the generation, transmission, distribution and sale of electric energy, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. Other Operations primarily includes the operations of the holding company. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. In reviewing its segment operating results, the Company focuses on operating income as its measure of segment profit and loss, and, therefore, has presented this information below. The following tables summarize the results of the Company's business segments for the three and nine months ended September 30, 2010 and 2009.

Three Months Ended September 30, 2010 (In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$ 723.0	$ 103.5	$ 243.1	$ 206.5	$ ---	$ (150.7)	$ 1,125.4
Cost of goods sold	311.2	64.8	178.9	207.6	---	(149.9)	612.6
Gross margin on revenues	411.8	38.7	64.2	(1.1)	---	(0.8)	512.8
Other operation and maintenance	110.8	11.6	22.0	1.8	(3.2)	(0.6)	142.4
Depreciation and amortization	53.1	5.2	12.6	---	2.8	---	73.7
Taxes other than income	16.9	3.3	1.4	0.1	0.8	---	22.5
Operating income (loss)	$ 231.0	$ 18.6	$ 28.2	$ (3.0)	$ (0.4)	$ (0.2)	$ 274.2
Total assets	$ 5,882.7	$ 1,643.1	$ 941.1	$ 105.4	$ 2,834.4	$ (3,879.3)	$ 7,527.4

Three Months Ended September 30, 2009 (In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$ 577.9	$ 91.5	$ 156.1	$ 127.2	$ ---	$ (107.4)	$ 845.3
Cost of goods sold	235.7	47.4	107.3	130.5	---	(106.8)	414.1
Gross margin on revenues	342.2	44.1	48.8	(3.3)	---	(0.6)	431.2
Other operation and maintenance	85.7	9.8	19.6	2.5	(3.6)	(1.0)	113.0
Depreciation and amortization	47.3	5.2	11.9	---	2.8	---	67.2
Taxes other than income	16.0	3.1	1.4	---	0.8	---	21.3
Operating income (loss)	$ 193.2	$ 26.0	$ 15.9	$ (5.8)	$ ---	$ 0.4	$ 229.7
Total assets	$ 5,223.5	$ 1,336.6	$ 839.7	$ 115.8	$ 2,602.8	$ (3,220.6)	$ 6,897.8

Nine Months Ended September 30, 2010 (In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$ 1,679.8	$ 311.7	$ 726.4	$ 641.2	$ ---	$ (470.7)	$ 2,888.4
Cost of goods sold	792.8	191.9	527.5	644.8	---	(467.8)	1,689.2
Gross margin on revenues	887.0	119.8	198.9	(3.6)	---	(2.9)	1,199.2
Other operation and maintenance	305.9	35.2	66.8	6.6	(10.8)	(2.7)	401.0
Depreciation and amortization	153.4	16.0	37.5	---	8.3	---	215.2
Taxes other than income	51.8	10.6	4.9	0.3	2.9	---	70.5
Operating income (loss)	$ 375.9	$ 58.0	$ 89.7	$ (10.5)	$ (0.4)	$ (0.2)	$ 512.5

Total assets	$ 5,882.7	$ 1,643.1	$ 941.1	$ 105.4	$ 2,834.4	$ (3,879.3)	$ 7,527.4

Nine Months Ended September 30, 2009 (In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$ 1,339.9	$ 300.8	$ 436.9	$ 436.7	$ ---	$ (418.3)	$ 2,096.0
Cost of goods sold	595.0	174.3	302.1	434.9	---	(414.8)	1,091.5
Gross margin on revenues	744.9	126.5	134.8	1.8	---	(3.5)	1,004.5
Other operation and maintenance	248.9	29.4	62.6	7.8	(10.2)	(3.4)	335.1
Depreciation and amortization	139.1	16.0	32.9	---	7.8	---	195.8
Taxes other than income	48.4	9.9	4.2	0.3	2.7	---	65.5
Operating income (loss)	$ 308.5	$ 71.2	$ 35.1	$ (6.3)	$ (0.3)	$ (0.1)	$ 408.1
Total assets	$ 5,223.5	$ 1,336.6	$ 839.7	$ 115.8	$2,602.8	$ (3,220.6)	$ 6,897.8

13. Commitments and Contingencies

Except as set forth below and in Note 14, the circumstances set forth in Notes 13 and 14 to the Company's Consolidated Financial Statements included in the Company's 2009 Form 10-K appropriately represent, in all material respects, the current status of the Company's material commitments and contingent liabilities.

OG&E Railcar Lease Agreement

At September 30, 2010, OG&E had a noncancellable operating lease with purchase options, covering 1,462 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. At the end of the lease term, which is January 31, 2011, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $31.5 million.

On February 10, 2009, OG&E executed a short-term lease agreement for 270 railcars in accordance with new coal transportation contracts with BNSF Railway and Union Pacific. These railcars were needed to replace railcars that have been taken out of service or destroyed. The lease agreement expired with respect to 135 railcars on November 2, 2009 and was not replaced. The lease agreement with respect to the remaining 135 railcars expired on March 5, 2010 and is now continuing on a month-to-month basis with a 30-day notice required by either party to terminate the agreement.

OG&E is also required to maintain all of the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

Oxley Litigation

OG&E has been sued by John C. Oxley D/B/A Oxley Petroleum et al. in the District Court of Haskell County, Oklahoma. This case has been pending for more than 11 years. The plaintiffs alleged that OG&E breached the terms of contracts covering several wells by failing to purchase gas from the plaintiffs in amounts set forth in the contracts. The plaintiffs' most recent Statement of Claim describes $2.7 million in take-or-pay damages (including interest) and $36 million in contract repudiation damages (including interest), subject to the limitation described below. In 2001, OG&E agreed to provide the plaintiffs with $5.8 million of consideration and the parties agreed to arbitrate the dispute. The arbitration hearing was completed and the final briefs were provided to the arbitration panel on March 17, 2010. On May 19, 2010, the panel issued an arbitration award in an amount less than the consideration previously paid by OG&E and, as a result, OG&E did not owe any additional amount. The Company now considers this case closed.

Natural Gas Measurement Cases

Will Price, et al. v. El Paso Natural Gas Co., et al. (Price I). On September 24, 1999, various subsidiaries of the Company were served with a class action petition filed in the District Court of Stevens County, Kansas by Quinque Operating Company and other named plaintiffs alleging the mismeasurement of natural gas on non-Federal lands. On April 10, 2003, the court entered an order denying class certification. On May 12, 2003, the plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended class action petition, and the court granted the motion on July 28, 2003. In its amended petition (the "Fourth Amended Petition"), OG&E and Enogex Inc. were omitted from the case but two of the Company's other subsidiary entities remained as defendants. The plaintiffs' Fourth Amended Petition seeks class certification and alleges that 60 defendants, including two of the Company's subsidiary entities, have improperly measured the volume of natural gas. The Fourth Amended Petition asserts theories of civil conspiracy, aiding and abetting, accounting and unjust enrichment. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

Discovery was conducted on the class certification issues, and the parties fully briefed these same issues. A hearing on class certification issues was held April 1, 2005. In May 2006, the court heard oral argument on a motion to intervene filed by Colorado Consumers Legal Foundation, which is claiming entitlement to participate in the putative class action. The court has not yet ruled on the motion to intervene.

The class certification issues were briefed and argued by the parties in 2005 and proposed findings of facts and conclusions of law on class certification were filed in 2007. On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On February 10, 2010 the court heard arguments on the rehearing request and by an order dated March 31, 2010, the court denied the plaintiffs' request for rehearing.

The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Will Price, et al. v. El Paso Natural Gas Co., et al. (Price II). On May 12, 2003, the plaintiffs (same as those in the Fourth Amended Petition in Price I above) filed a new class action petition in the District Court of Stevens County, Kansas naming the same defendants and asserting substantially identical legal and/or equitable theories as in the Fourth Amended Petition of the Price I case. OG&E and Enogex Inc. were not named in this case, but two subsidiary entities of the Company were named in this case. The plaintiffs allege that the defendants mismeasured the Btu content of natural gas obtained from or measured for the plaintiffs. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

Discovery was conducted on the class certification issues, and the parties fully briefed these same issues. A hearing on class certification issues was held April 1, 2005. In May 2006, the court heard oral argument on a motion to intervene filed by Colorado Consumers Legal Foundation, which is claiming entitlement to participate in the putative class action. The court has not yet ruled on the motion to intervene.

The class certification issues were briefed and argued by the parties in 2005 and proposed findings of facts and conclusions of law on class certification were filed in 2007. On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On February 10, 2010 the court heard arguments on the rehearing request and by an order dated March 31, 2010, the court denied the plaintiffs' request for rehearing.

The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Pipeline Rupture

On November 14, 2008, a natural gas gathering pipeline owned by Enogex ruptured in Grady County, near Alex, Oklahoma, resulting in a fire that caused injuries to one resident and destroyed three residential structures. After the incident, Enogex coordinated and assisted the affected residents. Enogex resolved matters with two of the residents and Enogex continued to seek resolution with a remaining resident. This resident filed a legal action in May 2009 in the District Court of Cleveland County, Oklahoma, against OGE Energy and Enogex. This matter was resolved by the parties on April 8, 2010. The ultimate resolution of this incident was not material to the Company in light of previously established reserves and insurance coverage.

Franchise Fee Lawsuit

On June 19, 2006, two OG&E customers brought a putative class action, on behalf of all similarly situated customers, in the District Court of Creek County, Oklahoma, challenging certain charges on OG&E's electric bills. The plaintiffs claim that OG&E improperly charged sales tax based on franchise fee charges paid by its customers. The plaintiffs also challenge certain franchise fee charges, contending that such fees are more than is allowed under Oklahoma law. OG&E's motion for summary judgment was denied by the trial judge. In January 2007, the Oklahoma Supreme Court "arrested" the District Court action until, and if, the propriety of the complaint of billing practices is determined by the OCC. In September 2008, the plaintiffs filed an application with the OCC asking the OCC to modify its order which authorizes OG&E to collect the challenged franchise fee charges. On December 9, 2009 the OCC issued an order dismissing the plaintiffs' request for a modification of the 1994 OCC order which authorized OG&E to collect and remit sales tax on franchise fee charges. In its December 9, 2009 order, the OCC advised the plaintiffs that the ruling does not address the question of whether OG&E's collection and remittance of such sales tax should be discontinued prospectively. On April 19, 2010, the OCC issued a final order dismissing with prejudice the applicants' claims for recovery of previously paid taxes on franchise fees and approving the closing of this matter. On June 10, 2010, the plaintiffs filed a motion in the District Court of Creek County, Oklahoma, asking the court to proceed with the original class action. On July 8, 2010, a hearing in this matter was held and the court granted the plaintiffs motion to lift the stay of discovery previously imposed by the Oklahoma Supreme Court but denied any other specific relief pending further action by the court. On August 4, 2010, OG&E filed an application to assume original jurisdiction and a petition for a writ of prohibition with the Oklahoma Supreme Court. On September 13, 2010, the Oklahoma Supreme Court issued a writ prohibiting the District Court judge from proceeding further in this case except to dismiss the case. On September 20, 2010, the plaintiffs filed a motion to reconsider this matter with the Oklahoma Supreme Court. While OG&E cannot predict the precise outcome of this lawsuit, based on the information known at this time, OG&E believes that this lawsuit will not have a material adverse effect on the Company's consolidated financial position or results of operations.

Environmental Matters

Water

OG&E filed an Oklahoma Pollutant Discharge Elimination ("OPDES") permit renewal application with the state of Oklahoma on August 4, 2008 for its Seminole generating station and received draft permits for review on both January 9, 2009 and December 4, 2009. OG&E provided comments on the draft permit in September 2010. In addition, OG&E filed OPDES permit renewal applications for its Muskogee, Mustang and Horseshoe Lake generating stations on March 4, 2009, April 3, 2009 and October 29, 2009, respectively. The draft permits were reviewed and comments have been submitted to the Oklahoma Department of Environmental Quality. OG&E has received final permits for its Horseshoe Lake and Seminole generating stations.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Condensed Consolidated Financial Statements. Except as otherwise stated above, in Note 14 below, in Item 1 of Part II of this Form 10-Q, in Notes 13 and 14 of Notes to the Company's Consolidated Financial Statements included in the Company's 2009 Form 10-K 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.

14. Rate Matters and Regulation

Except as set forth below, the circumstances set forth in Note 14 to the Company's Consolidated Financial Statements included in the Company's 2009 Form 10-K appropriately represent, in all material respects, the current status of any regulatory matters.

Completed Regulatory Matters

OG&E Renewable Energy Filing

OG&E announced in October 2007 its goal to increase its wind power generation over the following four years from its then current 170 megawatts ("MW") to 770 MWs and, as part of this plan, on December 8, 2008, OG&E issued a request for proposal ("RFP") to wind developers for construction of up to 300 MWs of new capability. In September 2009, OG&E reached agreements with two developers who are to build two new wind farms, totaling 280 MWs, in northwestern Oklahoma. Under the terms of the agreements, CPV Keenan is to build a 150 MW wind farm in Woodward County and Edison Mission Energy is to build a 130 MW facility in Dewey County near Taloga. The agreements are both 20-year power purchase agreements, under which the developers are to build, own and operate the wind generating facilities and OG&E will purchase their electric output. On January 5, 2010, OG&E received an order from the OCC approving the power purchase agreements and authorizing OG&E to recover the costs of the power purchase agreements through OG&E's fuel adjustment clause. The 150 MW wind farm is expected to be in service by the end of 2010 and the 130 MW wind farm is expected to be in service during the second quarter of 2011. OG&E will continue to evaluate renewable opportunities to add to its power-generation portfolio in the future.

OG&E Windspeed Transmission Line Project

OG&E filed an application on May 19, 2008 with the OCC requesting pre-approval to recover from Oklahoma customers the cost to construct a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma ("Windspeed"). The OCC subsequently authorized recovery at a construction cost of up to $218 million, including allowance for funds used during construction ("AFUDC"). At September 30, 2010, the construction costs and AFUDC incurred for the Windspeed transmission line were $210.9 million. The Windspeed transmission line was placed into service on March 31, 2010, with the recovery rider being implemented with the first billing cycle in April 2010.

OG&E Long-Term Gas Supply Agreements

On February 26, 2010, OG&E filed an application with the OCC requesting a waiver of the competitive bid rules to allow OG&E to negotiate desired long-term gas purchase agreements. On May 11, 2010, all parties to this case signed a settlement agreement in this matter requesting that the OCC issue an order granting a waiver of the competitive bid rules. A hearing on the settlement agreement was held on May 13, 2010 and the OCC issued an order approving the settlement agreement on May 27, 2010. On June 29, 2010, OG&E filed a separate application with the OCC seeking approval of four long-term gas purchase agreements, which would provide a 12-year supply of natural gas to OG&E and account for 25 percent of its currently projected natural gas fuel supply needs over the same time period. On September 26, 2010, OG&E filed a motion with the OCC to dismiss this case. A hearing in this matter was held on October 7, 2010 and the administrative law judge recommended that the case be dismissed without prejudice.

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2008

On July 20, 2009, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2008 fuel adjustment clause. On September 18, 2009, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. On May 5, 2010, all parties to this case signed a settlement agreement in this matter, stating that the various charges or credits in OG&E's fuel adjustment clause are based upon the actual prices paid for fuel, purchased power or purchased gas. The parties further stipulated that the charges collected by OG&E through its fuel adjustment clause from Oklahoma jurisdictional customers were calculated properly, were mathematically accurate and were collected in accordance with the fuel adjustment clause and all applicable OCC rules and orders for calendar year 2008. A hearing on the settlement agreement was held on May 26, 2010 and the OCC issued an order approving the settlement agreement on June 18, 2010.

OG&E Smart Grid Project

In February 2009, the ARRA was enacted into law. Several provisions of this law relate to issues of direct interest to the Company including, in particular, financial incentives to develop smart grid technology, transmission infrastructure and renewable energy. OG&E filed a grant request on August 4, 2009 for $130 million with the U.S. Department of Energy ("DOE") to be used for the Smart Grid application in OG&E's service territory. On October 27, 2009, OG&E received notification from the DOE that its grant had been accepted by the DOE for the full requested amount of $130 million. On April 21, 2010, OG&E and the DOE entered into a definitive agreement with regards to the award.

On March 15, 2010, OG&E filed an application with the OCC requesting pre-approval for system-wide deployment of smart grid technology and a recovery rider, including a credit for the Smart Grid grant. On July 1, 2010, the OCC approved a settlement among all parties to the proceeding. The key settlement terms were:

- Pre-approval for system-wide deployment of smart grid technology and authorization for OG&E to begin recovering the costs of the system-wide deployment of smart grid technology through a rider mechanism that will become effective in accordance with the order approving the settlement agreement;
- OG&E's total project costs eligible for recovery (those costs expended or accrued by OG&E prior to the termination of the period authorized by the DOE as eligible for grant funds) shall be capped at $366.4 million ("Smart Grid Cost"), inclusive of the DOE grant award amount. The Smart Grid Cost includes the cost of implementing the Norman, Oklahoma smart grid pilot program previously authorized by the OCC. Under the terms of the settlement, the Smart Grid Cost would be deemed to represent an investment that is fair, just and reasonable and in the public interest and to be prudent and will be recognized in OG&E's 2013 general rate case;
- To the extent that OG&E's total expenditure for system-wide deployment of smart grid technology during the eligible period exceeds the Smart Grid Cost, OG&E shall be entitled to offer evidence and seek to establish that the excess

above the Smart Grid Cost was prudently incurred and any such contention may be addressed in OG&E's 2013 rate case;

- Implementation of the recovery rider would commence with the first billing cycle in July 2010;
- Continued utilization of a return on equity previously approved by the OCC for other various recovery riders;
- The recovery rider shall be designed to collect, on a levelized basis, the revenue requirement associated with the estimated project cost of $357.4 million and shall be subject to a true-up in 2014 after the recovery rider expires, including a true-up for project costs, if any, in excess of $357.4 million but less than the Smart Grid Cost. Any over/under recovery remaining will be passed or credited through OG&E's fuel adjustment clause;
- OG&E guarantees that customers will receive the benefit of certain operations and maintenance cost reductions resulting from the smart grid deployment as a credit to the recovery rider;

- Beginning January 1, 2011, OG&E shall make available the smart grid web portal to all customers having a smart meter. OG&E shall expend funds to educate customers regarding the best use of the information available on the portal. In addition, OG&E shall make available to all customers who do not have internet access the opportunity to receive a monthly home energy report. This report shall be made available, free of charge, to customers eligible for the Company's Low Income Home Energy Assistance Program and/or Senior Citizen program who are without internet service. The incremental costs for web portal access, education and the providing of home energy reports free of charge are to be accumulated as a regulatory asset in an amount up to $6.9 million and recovered in base rates beginning in 2014;
- The stranded costs associated with OG&E's existing meters which are being replaced by smart meters will be accumulated in a regulatory asset and recovered in base rates beginning in 2014; and
- OG&E will file an application with the APSC related to the deployment of smart grid technology by the end of 2010.

Enogex 2010 Fuel Filing

Pursuant to its Statement of Operating Conditions ("SOC"), Enogex makes an annual fuel filing at the FERC to establish the zonal fuel percentages for each calendar year. The tracker mechanism set out in the SOC establishes prospectively the zonal fixed fuel factors (expressed as a percentage of natural gas shipped in the zone) for the upcoming calendar year. The collected fuel is later trued-up to actual usage and based on the value of the fuel at the time of usage.

On November 23, 2009, Enogex made its annual filing to establish the fixed fuel percentages for its East Zone and West Zone for calendar year 2010 ("2010 Fuel Year"). The FERC accepted the proposed zonal fuel percentages for the 2010 Fuel Year by an order dated April 23, 2010.

OG&E Crossroads Wind Project

In February 2010, OG&E signed memoranda of understanding for 197.8 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the Crossroads wind project ("Crossroads") located in Dewey County, Oklahoma. In April 2010, OG&E filed an application with the OCC requesting pre-approval of Crossroads and a rider to recover from Oklahoma customers the costs to construct Crossroads. On July 29, 2010, the OCC approved a settlement among all parties to the proceeding that would allow OG&E to build, own and operate the wind farm. The key settlement terms approved by the OCC were:

- Authorization for OG&E to begin recovering the costs of Crossroads through a rider mechanism that will be effective until new rates are implemented after OG&E's 2013 general rate case;
- Continued utilization of a return on equity previously approved by the OCC for other various recovery riders, subject to adjustment in the future to reflect the return on equity authorized in subsequent general rate cases;
- OG&E's capital costs for which it is entitled recovery for a 197.8 MW wind farm ("Capped Investment Amount") are $407.7 million;
- To the extent OG&E's total investment in Crossroads exceeds the Capped Investment Amount, OG&E shall be entitled to offer evidence and seek to establish that the excess above the Capped Investment Amount was prudently incurred and should be included in OG&E's rate base;
- If the three-year rolling average of Crossroads megawatt-hours ("MWH") of production (including a credit for energy not produced due to curtailments or other events caused by system emergencies, force majeure events, or transmission system issues) falls below 712,844 MWHs, OG&E shall file testimony demonstrating the appropriate operation of Crossroads as part of its fuel cost recovery filing; and
- OG&E has the opportunity to expand Crossroads by an additional 29.7 MWs (12 additional turbines). If the pending Southwest Power Pool ("SPP") interconnection study concludes on or before September 1, 2010, that these additional turbines can be interconnected at incremental costs below $4.7 million, the costs and associated recovery for these additional turbines shall be included in the Crossroads rider, and the Capped Investment Amount and the three-year

rolling average of MWH production will be adjusted to $469.7 million and 819,879 MWHs, respectively.

On July 31, 2010, the SPP released its interconnection study which identified that the incremental interconnection costs associated with the additional 29.7 MWs was $1.2 million. Therefore, OG&E chose to expand Crossroads by the additional 29.7 MWs with a total projected cost of the project, including AFUDC, to be $450 million, which is below the Capped Investment Amount of $469.7 million. OG&E entered into a turbine supply agreement with Siemens whereby OG&E is to acquire 227.5 MWs of wind turbine generation at a cost in excess of $300 million. OG&E expects Crossroads to be in service by the end of 2011.

OG&E is in the process of entering into an interconnection agreement with the SPP for Crossroads. As part of the multi-study interconnection process, the SPP is conducting a stability study to determine the impact Crossroads will have on the existing transmission system. The stability study will determine under what conditions, if any, that Crossroads can fully interconnect to the existing transmission system or whether Crossroads could be required to have a limited output until additional transmission network upgrades are constructed. At this time, the Company cannot predict the outcome of the stability study. A significant delay in OG&E being able to fully interconnect Crossroads to the existing transmission system could delay the in-service date of all or a portion of Crossroads and increase the cost of the project. However, based on current information, the Company does not believe that this stability study will result in an interconnection agreement that will materially affect the feasibility of Crossroads.

OG&E OU Spirit Wind Power Project

In connection with the OU Spirit wind farm, in January 2008, OG&E filed with the SPP for an interconnection agreement for this project. Since January 2008, the SPP has been studying this requested interconnection to determine the feasibility of the request, the impact of the interconnection on the SPP transmission system and the facilities needed to accommodate the interconnection. Given the backlog of interconnection requests at the SPP, there has been significant delay in completing the study process and in OG&E receiving a final interconnection agreement. On May 29, 2009, OG&E executed an interim interconnection agreement, allowing OU Spirit to interconnect to the transmission grid, subject to certain conditions. In connection with the interim interconnection agreement, OG&E posted a letter of credit with the SPP of $10.9 million, which was later reduced to $9.9 million in October 2009 and further reduced to $9.2 million in February 2010, related to the costs of upgrades required for OG&E to obtain transmission service from its new OU Spirit wind farm. The SPP filed the interim interconnection agreement with the FERC on June 29, 2009. On August 27, 2009, the FERC issued an order accepting the interim interconnection agreement, subject to certain conditions, which enables OU Spirit to interconnect into the transmission grid until the final interconnection agreement can be put in place, which is expected by the fourth quarter of 2010. Also, the SPP issued a revised interconnection study in September 2010 and concluded that OG&E's liability should only include non-shared network upgrades which have already been completed. Therefore, on October 1, 2010, the $9.2 million letter of credit was cancelled.

OG&E is in the process of negotiating a final interconnection agreement with the SPP. This final interconnection agreement will identify several network upgrades that must be constructed. Such network upgrades are expected to be placed in service by the end of 2014. While the SPP has conducted studies that permit OG&E to interconnect OU Spirit prior to the completion of these network upgrades, the SPP will conduct further studies in the event that higher priority projects are placed in service prior to when the network upgrades are completed. These higher priority projects include the 150 MW wind farm which is expected to be in service by the end of 2010 and the 130 MW wind farm which is expected to be in service during the second quarter of 2011, which OG&E has entered into power purchase agreements. These further SPP studies may result in OU Spirit's output being limited from time to time until the network upgrades are completed.

Market-Based Rate Authority

On December 22, 2003, OG&E and OERI filed a triennial market power update with the FERC based on the supply margin assessment test. On May 13, 2004, the FERC directed all utilities with pending three year market-based reviews to revise the generation market power portion of their three year review to address two new interim tests, a pivotal supplier screen test and a market share screen test. On February 7, 2005, OG&E and OERI submitted a compliance filing to the FERC that applied the interim tests to OG&E and OERI. On June 7, 2005, the FERC issued an order finding that OG&E and OERI had failed the market share screen test meant to determine whether entities with market-based rate authority have market power in wholesale power markets. Based on the failed market share screen test, the FERC established a rebuttable presumption that OG&E and OERI have the ability to exercise market power in OG&E's control area. On August 8, 2005, OG&E and OERI informed the FERC that they would: (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 would be filed with the FERC and that OG&E and OERI would not make such sales under their respective market-based rate tariffs. On March 21, 2006, the FERC issued an order conditionally accepting OG&E's and OERI's proposal to mitigate the presumption of market power in OG&E's control area. First, the FERC accepted the additional information related to first-tier markets submitted by OG&E and OERI, and concluded that OG&E and OERI satisfy the FERC's generation market power standard for directly interconnected first-tier control areas. Second, the FERC directed OG&E and OERI to make certain revisions to its mitigation proposal and file a cost-based rate tariff for short-term sales (one week or less) made within OG&E's control area. The FERC also expanded the scope of the proposed mitigation to all sales made within OG&E's control area (instead of only to sales sinking to load within OG&E's control area). As part of the market-based rate matter, OG&E and OERI have filed a series of tariff revisions to comply with the FERC orders and such revisions have been accepted by the FERC. Also, as part of the mitigation for the failed market share screen test discussed above, on an ongoing basis, OG&E and OERI file change of status reports and triennial market power reports according to the FERC orders and regulations. In July 2009, OG&E and OERI filed a triennial market power update with the FERC which reported that there have been no significant changes to OG&E's and OERI's market-based rate authority. On July 21, 2010, the FERC issued an order accepting OG&E's July 2009 triennial market power update and found no change from the previous market-based rate authorizations.

On October 14, 2010, OERI filed with the FERC a Notice of Cancellation of OERI's market-based rate tariff. OERI does not currently make wholesale sales pursuant to its market-based rate authorization, has not done so in several years and does not anticipate doing so in the foreseeable future. Additionally, OERI has no outstanding transactions under its market-based rate tariff, so no customers will be affected by the filing. OERI also requested a waiver of the prior notice filing requirement to allow termination of its market-based rate tariff effective as of October 13, 2010.

Tallgrass Joint Venture

In July 2008, OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture, conducting business as Tallgrass Transmission L.L.C. ("Tallgrass") to construct high-capacity transmission line projects. The Company owns 50 percent of Tallgrass. Tallgrass is intended to allow the participating companies to lead development of renewable wind energy projects by sharing capital costs associated with transmission construction. As previously disclosed, Tallgrass' initial proposed projects were to include 765 kilovolt ("kV") lines from Woodward 120 miles northwest to Guymon in the Oklahoma Panhandle and from Woodward 50 miles north to the Kansas border. However, on April 27, 2010, the SPP approved these projects to be constructed as 345 kV. Therefore, these transmission lines are expected to be built by OG&E as discussed below. In conjunction with the approval that these projects should be constructed as 345 kV lines, the Company wrote off $1.3 million in the second quarter of 2010 for costs that had been previously incurred and deferred related to Tallgrass.

Pending Regulatory Matters

OG&E Arkansas OU Spirit Application and Renewable Energy Filing

On August 16, 2010, OG&E filed an application with the APSC requesting an order determining (i) that the construction of OU Spirit is prudent and is in the public's interest, (ii) OG&E may begin deferring the Arkansas jurisdictional portion of the OU Spirit costs as a regulatory asset beginning September 1, 2010, (iii) OG&E may implement a renewable energy temporary surcharge to recover OU Spirit regulatory asset costs until the implementation of new rate schedules in the next general rate filing and (iv) OG&E may recover, through the fuel adjustment clause, the costs of purchasing power under two wind purchase power agreements totaling 280 MWs, which were signed in September 2009, as a result of an RFP issued by OG&E in December 2008. The agreements are both 20-year power purchase agreements, under which the developers are to build, own and operate the wind generating facilities and OG&E will purchase their electric output. The 150 MW wind farm is expected to be in service by the end of 2010 and the 130 MW wind farm is expected to be in service during the second quarter of 2011. A procedural schedule has not been established in this matter.

OG&E 2010 Arkansas Rate Case Filing

OG&E began developing a rate case filing for the Arkansas jurisdiction in early 2010. In June 2010, OG&E filed notice with the APSC of its intent to seek an increase in its electric rates, anticipating a rate case filing no sooner than August 2010. On September 28, 2010, OG&E filed its rate case with the APSC requesting a rate increase of $17.7 million, to recover the cost of significant electric system expansions and upgrades, including high-voltage transmission lines and wind energy, that have been completed since the last rate filing in August 2008, as well as rising operating costs. If approved, the targeted implementation date for new electric rates is expected to be during the third quarter of 2011. A hearing in this matter is scheduled for May 24, 2011.

OG&E SPP Cost Tracker

On October 7, 2010, OG&E filed an application with the OCC seeking recovery of the Oklahoma jurisdictional portion of (i) costs associated with transmission upgrades and facilities that have been approved by the SPP in its regional planning processes and constructed by other transmission owners throughout the SPP that have been allocated to OG&E through the FERC-approved transmission rates and (ii) SPP administrative fees. OG&E requested authorization to implement a cost tracker in order to recover from its retail customers the third party project costs discussed above and to collect its administrative SPP cost assessment levied under Schedule 1A of the SPP open access transmission tariff ("OATT"), which is currently recovered in base rates. OG&E also requested authorization to establish a regulatory asset effective January 1, 2011 in order to give OG&E the opportunity to recover such costs that will be paid but not recovered until the cost tracker is made effective. A procedural schedule has not been established in this matter.

OG&E FERC Transmission Rate Incentive Filing

On October 12, 2010, OG&E submitted to the FERC revised tariff sheets to its OATT and to the SPP OATT to implement two limited transmission rate incentives. If approved by the FERC, the revised tariff sheets will authorize recovery of 100 percent of all prudently incurred construction work in progress in rate base for specific 345kV Extra High Voltage ("EHV") transmission projects to be constructed and owned by OG&E within the SPP's region. In addition, if approved by the FERC, the revised tariff sheets will authorize OG&E to recover 100 percent of all prudently incurred development and construction costs if the transmission projects are abandoned or cancelled, in whole or in part, for reasons beyond OG&E's control. OG&E has requested an effective date of January 1, 2011.

SPP Transmission/Substation Projects

The SPP is a regional transmission organization under the jurisdiction of the FERC that was created to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity. The SPP does not build transmission though the SPP's tariff contains rules that govern the transmission construction process. Transmission owners complete the construction and then own, operate and maintain transmission assets within the SPP region. When the SPP Board of Directors approves a project, the transmission provider in the area where the project is needed has the first obligation to build.

There are several studies currently under review at the SPP including the EHV study that focuses on year 2026 and beyond to address issues of regional and interregional importance. The EHV study suggests overlaying the SPP footprint with a 345 kV, 500kV and 765kV transmission system and integrating it with neighboring regional entities. In 2009, the SPP Board of Directors approved a new report that recommended restructuring the SPP's regional planning processes to focus on the construction of a robust transmission system, large enough in both scale and geography, to provide flexibility to meet the SPP's future needs. OG&E expects to actively participate in the ongoing study, development and transmission growth that may result from the SPP's plans.

In 2007, the SPP notified OG&E to construct 44 miles of new 345 kV transmission line which will originate at OG&E's existing Sooner 345 kV substation and proceed generally in a northerly direction to the Oklahoma/Kansas Stateline (referred to as the Sooner-Rose Hill project). At the Oklahoma/Kansas Stateline, the line will connect to the companion line being constructed in Kansas by Westar Energy. The line is estimated to be in service by June 2012. The capital expenditures related to this project are presented in the summary of capital expenditures for known and committed projects in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

In January 2009, OG&E received notification from the SPP to begin construction on 50 miles of new 345 kV transmission line and substation upgrades at OG&E's Sunnyside substation, among other projects. In April 2009, Western Farmers Electric Cooperative ("WFEC") assigned to OG&E the construction of 50 miles of line designated by the SPP to be built by the WFEC. The new line will extend from OG&E's Sunnyside substation near Ardmore, Oklahoma, 100 miles to the Hugo substation owned by the WFEC near Hugo, Oklahoma. OG&E began preliminary line routing and acquisition of rights-of-way in June 2009. When construction is completed, which is expected in April 2012, the SPP will allocate a portion of the annual revenue requirement to OG&E customers according to the base-plan funding mechanism as provided in the SPP tariff for application to such improvements. The capital expenditures related to this project are presented in the summary of capital expenditures for known and committed projects in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future

Capital Requirements."

On April 28, 2009, the SPP approved the Balanced Portfolio 3E projects. Balanced Portfolio 3E includes four projects to be built by OG&E and includes: (i) construction of 120 miles of transmission line from OG&E's Seminole substation in a northeastern direction to OG&E's Muskogee substation at a cost of $180 million for OG&E, which is expected to be in service by December 2013, (ii) construction of 72 miles of transmission line from OG&E's Woodward District EHV substation in a southwestern direction to the Oklahoma/Texas Stateline to a companion transmission line to be built by Southwestern Public Service to its Tuco substation at a cost of $120 million for OG&E, which is expected to be in service by April 2014, (iii) construction of 38 miles of transmission line from OG&E's Sooner substation in an eastern direction to the Grand River Dam Authority Cleveland substation at an estimated cost of $65 million for OG&E, which is expected to be in service by December 2012 and (iv) construction of a new substation near Anadarko which is expected to consist of a 345/138 kV transformer and substation breakers and will be built in OG&E's portion of the Cimarron-Lawton East Side 345 kV line at an estimated cost of $15 million for OG&E, which is expected to be in service by December 2011. On June 19, 2009, OG&E received a notice to construct the Balanced Portfolio 3E projects from the SPP. On July 23, 2009, OG&E responded to the SPP that OG&E will construct the Balanced Portfolio 3E projects discussed above beginning in late 2010 or early 2011. The capital expenditures related to the Balanced Portfolio 3E projects are presented in the summary of capital expenditures for known and committed projects in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

On April 27, 2010, the SPP approved, contingent upon approval by the FERC of a regional cost allocation methodology filed with the FERC by the SPP, a set of transmission projects titled "Priority Projects." The Priority Projects consist of several transmission projects, two of which have been assigned to OG&E. The 345 kV projects include: (i) construction of 92 miles of transmission line from OG&E's Woodward District EHV substation to a companion transmission line to be built by Southwestern Public Service to its Hitchland substation in the Texas Panhandle at a cost of $180 million for OG&E, which is expected to be in service by June 2014 and (ii) construction of 80 miles of transmission line from OG&E's Woodward District EHV substation to a companion transmission line at the Kansas border to be built by either Mid-Kansas Electric Company ("MKEC") or another company assigned by MKEC at a cost of $135 million to OG&E, which is expected to be in service by December 2014. On June 17, 2010, the FERC approved the cost allocation filed by the SPP and notices to construct these Priority Projects were issued by the SPP on June 30, 2010. On September 27, 2010, OG&E responded to the SPP that OG&E will construct the Priority Projects discussed above beginning in June 2012. The capital expenditures related to the Priority Projects are presented in the summary of capital expenditures for known and committed projects in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

Enogex FERC Section 311 2007 Rate Case

On October 1, 2007, Enogex made its required triennial rate filing at the FERC to update its Section 311 maximum interruptible transportation rates for Section 311 service in the East Zone and West Zone. Enogex's filing requested an increase in the maximum zonal rates and proposed to place such rates into effect on January 1, 2008. A number of parties intervened and some also filed protests. Settlement discussions have continued between the parties. With respect to the 2007 Section 311 rate case, Enogex did not place the increased rates set forth in its October 2007 rate filing into effect but rather continued to provide interruptible Section 311 service under the maximum Section 311 rates for both zones approved by the FERC in the previous rate case. Neither a final settlement nor an order from the FERC has been entered for the 2007 triennial filing. With the filing of Enogex's 2009 rate case discussed below, the rate period for the 2007 rate case became a limited locked-in period from January 2008 through May 2009.

On November 13, 2007, one of the protesting intervenors filed to consolidate the Enogex 2007 rate case with a separate Enogex application pending before the FERC allowing Enogex to lease firm capacity to Midcontinent Express Pipeline, LLC ("MEP") and with separate applications filed by MEP with the FERC for a certificate to construct and operate the new MEP pipeline and to lease firm capacity from Enogex. Enogex and MEP separately opposed this intervenor's protests and assertions in its initial and subsequent pleadings. On July 25, 2008, the FERC issued an order approving the MEP project including the approval of a limited jurisdiction certificate authorizing the Enogex lease agreement with MEP denying the request for consolidation and rejecting all claims raised by protestors regarding the lease agreement. Accordingly, Enogex proceeded with the construction of facilities necessary to implement this service. On August 25, 2008, the same protestor sought rehearing which the FERC denied. Enogex commenced service to MEP under the lease agreement on June 1, 2009. On July 16, 2009, the protestor filed, with the United States Court of Appeals for the District of Columbia Circuit, a petition for review of the FERC's orders approving the MEP construction and the MEP lease of capacity from Enogex requesting that such orders be modified or set aside on the grounds that they are arbitrary, capricious and contrary to law. The petitioner, the FERC and intervening parties were given an opportunity to brief the issues. Enogex participated in the filing of a joint intervenors' brief in support of the FERC's orders in this matter on June 11, 2010. Final briefing was completed on July 16, 2010. The Court of Appeals heard arguments of the parties on October 15, 2010. Enogex cannot predict what action the court will take or the timing of that action.

Enogex FERC Section 311 2009 Rate Case

On March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for its new firm East Zone Section 311 transportation service and to revise the rates for its existing East and West Zone interruptible Section 311 transportation service. In anticipation of offering this new service, Enogex had filed with the FERC, as required by the FERC's regulations, a revised SOC Applicable to Transportation Services to describe the terms, conditions and operating arrangements for the new service. Enogex made the SOC filing on February 27, 2009. Enogex began offering firm East Zone Section 311 transportation service on April 1, 2009. The revised East and West Zone zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for the firm East Zone Section 311 transportation service and the increase in the rates for East and West Zone and interruptible Section 311 service are being collected, subject to refund, pending the FERC approval of the proposed rates. A number of parties intervened in both the rate case and the SOC filing and some additionally filed protests. Enogex filed answers to the interventions and protests in both matters. The FERC Staff served data requests on Enogex seeking additional information regarding various aspects of the filing and Enogex has submitted responses. On August 19, 2009, the FERC issued an order extending the time for action until it can make a determination whether Enogex's rates are fair and equitable or until the FERC determines that formal proceedings are necessary. The August 19, 2009 order also directed the FERC Staff to report to the FERC by December 29, 2009 on the status of settlement negotiations. On January 4, 2010, the FERC Staff submitted its initial settlement offer ("Offer") proposing various adjustments to Enogex's filed cost of service. On April 27, 2010, Enogex submitted comments to the FERC Staff stating that it would agree to the Offer, contingent upon all parties agreeing to support or not oppose. Parties have until December 10, 2010 to submit comments stating whether they support, or do not oppose, the FERC Staff's Offer.

Enogex Storage SOC filing

Enogex filed with the FERC a new SOC applicable to storage services that replaced Enogex's existing storage SOC effective July 30, 2010. Among other things, the new storage SOC updates the general terms and conditions for providing storage services. On August 31, 2010, the new storage SOC was filed via eTariff with the FERC and a FERC order is pending.

Enogex Mid-Year 2010 Fuel Filing

Pursuant to its SOC, Enogex makes an annual fuel filing at the FERC to establish the zonal fuel percentages for each calendar year as discussed above. As Enogex anticipated over recovering fuel for the remainder of 2010, Enogex filed a mid-year fuel filing on July 1, 2010. The proposed reduced rates were effective August 1, 2010 and are subject to refund pending FERC approval. Concurrently, Enogex asked the FERC for authority to change the timing of its annual filing to February 15 and for implementation of a new fuel year with a 12-month period of April 1 through March 31. If both requests are approved, the reduced rates will remain in effect until March 31, 2011, at which time new rates for the period from April 1, 2011 to March 31, 2012 will be implemented. No parties protested the Enogex requests and a FERC order is pending.

State Legislative Initiative

House Bill 3028 ("HB 3028") became effective in May 2010 and established an Oklahoma renewable portfolio standard with a statewide goal of renewable energy capacity (on an installed electric generation capacity basis) of 15 percent by year 2015. HB 3028 also designated natural gas as the preferred fuel for all new fossil fuel electric generation in Oklahoma until year 2020, but provides that the OCC may determine that a fossil fuel other than natural gas is in the best interest of customers. By the year 2012, OG&E expects that its installed electric generation capacity basis for wind-powered units will be 10 percent.

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

Introduction

OGE Energy Corp. ("OGE Energy" and 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 four business segments: (i) electric utility, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing.

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

Enogex LLC and its subsidiaries ("Enogex") are providers of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream LLC joint venture through Enogex Atoka LLC, a wholly-owned subsidiary of Enogex Gathering & Processing LLC.

On October 5, 2010, OGE Energy entered into an Investment Agreement with Bronco Midstream Holdings LLC ("Bronco"), a subsidiary of ArcLight Energy Partners Fund IV, L.P. ("ArcLight"), and Enogex Holdings LLC, an indirect wholly-owned subsidiary of OGE Energy ("Enogex Holdings") pursuant to which Bronco agreed to make an initial equity investment in Enogex Holdings in an amount equal to $183,150,000 in exchange for a 9.9 percent membership interest in Enogex Holdings, the parent company of Enogex. Prior to the closing of the transaction (which is expected to occur on November 1, 2010), 100 percent of the equity of OGE Energy Resources, Inc. ("OERI"), a natural gas marketing subsidiary currently owned by OGE Energy, will be contributed to Enogex.

Overview

Financial Strategy

The Company's mission is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customers' needs for energy and related services in a safe, reliable and efficient manner. The Company intends to execute its vision by focusing on its regulated electric utility business and unregulated midstream natural gas business. The Company intends to maintain the majority of its assets in the regulated utility business complemented by its natural gas pipeline business. The Company's financial objectives from 2010 through 2012 include a long-term annual earnings growth rate of five to seven percent on a weather-normalized basis, maintaining a strong credit rating and an annual dividend growth rate of two percent subject to approval by the Company's Board of Directors. The target payout ratio for the Company is to pay out as dividends no more than 60 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. The Company believes it can accomplish these financial objectives by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and maintaining strong regulatory and legislative relationships.

Summary of Operating Results

Three Months Ended September 30, 2010 as Compared to Three Months Ended September 30, 2009

Net income attributable to OGE Energy was $163.1 million, or $1.65 per diluted share, during the three months ended September 30, 2010, as compared to $136.8 million, or $1.40 per diluted share, during the same period in 2009. The increase in net income attributable to OGE Energy of $26.3 million, or 19.2 percent, or $0.25 per diluted share, during the three months ended September 30, 2010 as compared to the same period in 2009 was primarily due to:

- An increase in net income at OG&E of $18.9 million or 15.3 percent, or $0.17 per diluted share of the Company's common stock, primarily due to a higher gross margin on revenues ("gross margin") mainly due to warmer weather in OG&E's service territory, rate increases and riders partially offset by higher other operation and maintenance expense;
- An increase in net income at Enogex of $6.1 million or 33.7 percent, or $0.06 per diluted share of the Company's common stock, primarily due to a higher gross margin mainly due to higher processing spreads, higher natural gas liquids ("NGL") prices, higher natural gas prices and increased volumes partially offset by higher other operation and maintenance expense; and
- A decrease in the net loss at OERI of $1.7 million or 45.9 percent, or $0.02 per diluted share of the Company's common stock, primarily due to a lower gross margin loss and lower other operation and maintenance expense partially offset by a lower income tax benefit.

Nine Months Ended September 30, 2010 as Compared to Nine Months Ended September 30, 2009

Net income attributable to OGE Energy was $264.6 million, or $2.68 per diluted share, during the nine months ended September 30, 2010, as compared to $224.1 million, or $2.31 per diluted share, during the same period in 2009. Included in net income attributable to OGE Energy during the nine months ended September 30, 2010 was a one-time, non-cash charge of $11.4 million, or $0.11 per diluted share, related to the elimination of the tax deduction for the Medicare Part D subsidy (discussed in Note 7 of Notes to Condensed Consolidated Financial Statements). The increase in net income attributable to OGE Energy of $40.5 million, or 18.1 percent, or $0.37 per diluted share, during the nine months ended September 30, 2010 as compared to the same period in 2009 was primarily due to:

- An increase in net income at OG&E of $22.4 million or 12.4 percent, or $0.19 per diluted share of the Company's common stock, primarily due to a higher gross margin mainly due to rate increases and riders and warmer weather in OG&E's service territory partially offset by higher other operation and maintenance expense and higher income tax expense mainly attributable to the elimination of the tax deduction for the Medicare Part D subsidy (discussed in Note 7 of Notes to Condensed Consolidated Financial Statements);

- An increase in net income at Enogex of $24.4 million or 49.3 percent, or $0.24 per diluted share of the Company's common stock, primarily due to a higher gross margin mainly due to higher processing spreads, higher NGLs prices, higher natural gas prices and increased volumes partially offset by higher other operation and maintenance expense and higher income tax expense mainly attributable to the elimination of the tax deduction for the Medicare Part D subsidy (discussed in Note 7 of Notes to Condensed Consolidated Financial Statements);
- An increase in the net loss at OGE Energy of $3.5 million, or $0.03 per diluted share of the Company's common stock, primarily due to higher income tax expense mainly attributable to the elimination of the tax deduction for the Medicare Part D subsidy (discussed in Note 7 of Notes to Condensed Consolidated Financial Statements) partially offset by lower interest expense primarily due to lower average commercial paper borrowings during the nine months ended September 30, 2010; and
- An increase in the net loss at OERI of $2.8 million or 66.7 percent, or $0.03 per diluted share of the Company's common stock, primarily due to a lower gross margin partially offset by lower other operation and maintenance expense and a higher income tax benefit.

Recent Developments and Regulatory Matters

OG&E Smart Grid Project

On July 1, 2010, the OCC approved a settlement with all parties to the OCC consideration of OG&E's application for pre-approval for system-wide deployment of smart grid technology and a recovery rider. The recovery rider was implemented with the first billing cycle in July 2010. For a discussion of the settlement agreement terms related to OG&E's Smart Grid application, see Note 14 of Notes to Condensed Consolidated Financial Statements.

OG&E Crossroads Wind Project

On June 28, 2010, a settlement agreement was reached with all the parties to the OCC consideration of OG&E's application for pre-approval of the 197.8 megawatts ("MW") of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the Crossroads wind project ("Crossroads") and a recovery rider. On July 29, 2010, the OCC approved a settlement among all parties to the proceeding that would allow OG&E to build, own and operate the wind farm. For a discussion of the settlement agreement terms approved by the OCC related to OG&E's Crossroads application, see Note 14 of Notes to Condensed Consolidated Financial Statements.

OG&E is in the process of entering into an interconnection agreement with the Southwest Power Pool ("SPP") for Crossroads. As part of the multi-study interconnection process, the SPP is conducting a stability study to determine the impact Crossroads will have on the existing transmission system. The stability study will determine under what conditions, if any, that Crossroads can fully interconnect to the existing transmission system or whether Crossroads could be required to have a limited output until additional transmission network upgrades are constructed. At this time, the Company cannot predict the outcome of the stability study. A significant delay in OG&E being able to fully interconnect Crossroads to the existing transmission system could delay the in-service date of all or a portion of Crossroads and increase the cost of the project. However, based on current information, the Company does not believe that this stability study will result in an interconnection agreement that will materially affect the feasibility of Crossroads.

OG&E Arkansas OU Spirit Application and Renewable Energy Filing

On August 16, 2010, OG&E filed an application with the APSC requesting an order determining (i) that the construction of OU Spirit is prudent and is in the public's interest, (ii) OG&E may begin deferring the Arkansas jurisdictional portion of the OU Spirit costs as a regulatory asset beginning September 1, 2010; (iii) OG&E may implement a renewable energy temporary surcharge to recover OU Spirit regulatory asset costs until the implementation of new rate schedules in the next general rate filing; and (iv) OG&E may recover, through the fuel adjustment clause, the costs of purchasing power under two wind purchase power agreements totaling 280 MWs, which were signed in September 2009, as a result of an RFP issued by OG&E in December 2008. The agreements are both 20-year power purchase agreements, under which the developers are to build, own and operate the wind generating facilities and OG&E will purchase their electric output. The 150 MW wind farm is expected to be in service by the end of 2010 and the 130 MW wind farm is expected to be in service during the second quarter of 2011. A procedural schedule has not been established in this matter.

OG&E 2010 Arkansas Rate Case Filing

OG&E began developing a rate case filing for the Arkansas jurisdiction in early 2010. In June 2010, OG&E filed notice with the APSC of its intent to seek an increase in its electric rates, anticipating a rate case filing no sooner than August 2010. On September 28, 2010, OG&E filed its rate case with the APSC requesting a rate increase of $17.7 million, to recover the cost of significant electric system expansions and upgrades, including high-voltage transmission lines and wind energy, that have been completed since the last rate filing in August 2008, as well as rising operating costs. If approved, the targeted implementation date for new electric rates is expected to be during the third quarter of 2011. A hearing in this matter is scheduled for May 24, 2011.

Gathering and Processing System Expansions

Texas Panhandle Expansions

Enogex expanded its gathering infrastructure in the Wheeler County, Texas area with the construction of 16 miles of 10-inch steel pipe, as well as the addition of 5,400 horsepower of compression, which became operational and were placed in service during the third quarter of 2010. The capital expenditures associated with this project were $13 million.

Enogex is in the process of constructing a new 120 million cubic feet per day (“MMcf/d”) cryogenic processing plant in Wheeler County, Texas. The new plant, which will be supported by the installation of 9,400 horsepower of field compression, is expected to be in service by January 2012. The capital expenditures associated with this project are expected to be $109 million.

Western Oklahoma System Expansions

As additional support for the strong production needs surrounding Enogex’s new Clinton plant, Enogex plans to build an additional six miles of 16-inch high pressure gathering pipe and construct a new compressor station designed to handle 6,700 horsepower of single-stage compression. The initial 4,000 horsepower at the compressor station, and the high pressure gathering pipe, were placed in service in August 2010, with an additional 1,340 horsepower estimated to be installed by the end of 2010, and another 1,340 horsepower expected to be added during 2011. The capital expenditures for this construction are expected to be $17 million.

Enogex is in the process of constructing a new 200 MMcf/d cryogenic processing plant in Canadian County, Oklahoma. The new plant, which will have inlet and residue compression and will be supported by the installation of 31 miles of 20-inch gathering pipeline, as well as 11 miles of 24-inch transmission pipeline providing takeaway capacity from the plant tailgate, is expected to be in service by January 2012. The capital expenditures associated with this project are expected to be $130 million.

Transportation System Expansions

In order to accommodate additional deliveries to Bennington, Oklahoma, Enogex is planning to add an incremental 13,800 horsepower of gas turbine compression at its Bennington compressor station, as well as other system upgrades. This project is expected to be in service in the fourth quarter of 2010. The capital expenditures associated with these projects are expected to be $27 million.

In January 2009, Enogex entered into a Facility Construction, Ownership and Operating Agreement for the installation of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Construction of the required facilities was completed during

August 2010. Aid in Construction payments of $37.2 million received in excess of construction costs have been recognized as Deferred Revenues on the Company's Condensed Consolidated Balance Sheet and will be amortized on a straight-line basis of $1.2 million per year over the life of the related Intrastate Firm Transportation Services agreement under which service will commence in June 2011.

2010 Outlook

The Company's 2010 ongoing earnings guidance has been increased from between $265 million and $290 million of net income, or $2.70 to $2.95 per average diluted share, to between $292 million and $302 million of net income, or $2.95 to $3.05 per average diluted share. The Company projects OG&E to earn at the upper end of the earnings range of $207 million to $217 million, or $2.10 to $2.20 per average diluted share, in 2010, which remained unchanged from the Company's previously reported ongoing earnings guidance, and the Company projects Enogex to earn between $84 million to $94 million, or $0.85 to $0.95 per average diluted share, in 2010, up from the Company's previously reported ongoing earnings guidance of $63 million to $85 million, or $0.64 to $0.86 per average diluted share. However, certain key assumptions previously disclosed have changed which are shown below. All other assumptions are unchanged from those included in the earnings guidance in the Company’s Annual Report on Form 10-K for the year ended December 31, 2009 (“2009 Form 10-K”) and the Company’s Form 10-Q for the quarter ended June 30, 2010.

2010 Ongoing Earnings Guidance:

- Excludes a one-time, non-cash charge recorded in March 2010 of $11.4 million, or $0.11 per average diluted share, related to the elimination of the tax deduction for the Medicare Part D subsidy. Of the $11.4 million charge, $7.0 million related to OG&E, $2.0 million related to Enogex and $2.4 million related to the holding company.
- Includes a projected increase in 2010 in income tax expense of $2.3 million, or $0.02 per average diluted share, related to the elimination of the tax deduction for the Medicare Part D subsidy. Of the $2.3 million projected increase, $1.9 million relates to OG&E, $0.2 million relates to Enogex and $0.2 million relates to the holding company.

Key factors and assumptions that have changed include:

	Previous Guidance	Updated Guidance	Reason for Change in Guidance
OG&E			
Earnings per share	No change	No change	Increase in gross margin experienced as a result of favorable weather during 2010 will be offset by increased operating expenses during 2010 primarily resulting from increased maintenance at some of OG&E’s power plants and higher postretirement benefit costs.
Enogex			
Gross margin	$400 million	$420 million	Higher gross margin in the processing business.
Gathering volume growth	8 percent - 10 percent	6 percent	Based on projections for remainder of 2010.
Noncontrolling interest	N/A	Deduction of $2.5 million to pre-tax net income for net income attributable to noncontrolling interest	Related to the 9.9 percent equity sale to ArcLight effective November 1, 2010.
Earnings per share	N/A	A loss at OERI of between $7 million and $9 million, or $0.07 to $0.09 per average diluted share	Unchanged and previously included in the holding company 2010 guidance.
Holding Company			
Earnings per share	Loss of $11 million to $13 million, or $0.11 to	Loss of $4 million, or	OERI’s loss included in Enogex’s results due to the

	$0.13 per average diluted share	$0.04 per average diluted share	contribution of OERI to Enogex.

OG&E has significant seasonality in its earnings. OG&E typically shows minimal earnings in the first and fourth quarters with a majority of earnings in the third quarter due to the seasonal nature of air conditioning demand.

Ongoing earnings, which as indicated above excludes the one-time, non-cash charge of $11.4 million associated with the elimination of the tax deduction for the Medicare Part D subsidy as a result of the recent health care legislation, is a non-GAAP financial measure. As the Medicare Part D tax subsidy represents a charge which management believes will not be recurring on a regular basis, management believes that the presentation of Ongoing Earnings and Ongoing earnings per share (“EPS”) provides useful information to investors, as it provides them an additional relevant comparison of the Company’s performance across periods. Reconciliations of Ongoing Earnings and Ongoing EPS to generally accepted accounting principles (“GAAP”) net income and GAAP EPS are provided below.

Reconciliation of projected ongoing earnings (loss) to projected GAAP net income

(In millions)	Twelve Months Ended December 31, 2010							
	OG&E		Enogex		Holding Company		Consolidated	
	Low	High	Low	High	Low	High	Low	High
Ongoing earnings (loss)	$ 207.0	$ 217.0	$ 84.0	$ 94.0	$ (4.0)	$ (4.0)	$ 292.0	$ 302.0
Medicare Part D tax subsidy	(7.0)	(7.0)	(2.0)	(2.0)	(2.4)	(2.4)	(11.4)	(11.4)
Projected GAAP net income	$ 200.0	$ 210.0	$ 82.0	$ 92.0	$ (6.4)	$ (6.4)	$ 280.6	$ 290.6

Reconciliation of projected ongoing EPS to projected GAAP EPS

	Twelve Months Ended December 31, 2010							
	OG&E		Enogex		Holding Company		Consolidated	
	Low	High	Low	High	Low	High	Low	High
Ongoing EPS	$ 2.10	$ 2.20	$ 0.85	$ 0.95	$ (0.04)	$ (0.04)	$ 2.95	$ 3.05
Medicare Part D tax subsidy	(0.07)	(0.07)	(0.02)	(0.02)	(0.02)	(0.02)	(0.11)	(0.11)
Projected GAAP EPS	$ 2.03	$ 2.13	$ 0.83	$ 0.93	$ (0.06)	$ (0.06)	$ 2.84	$ 2.94

Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA") is used as a supplemental financial measure by external users of the Company's financial statements such as investors, commercial banks and others; therefore, the Company has included the table below which provides a reconciliation of projected EBITDA to projected ongoing net income attributable to Enogex LLC at the midpoint of Enogex's earnings assumptions for 2010.

Reconciliation of projected EBITDA to projected ongoing net income attributable to Enogex LLC

(In millions)	Twelve Months Ended December 31, 2010 (A)
Ongoing net income attributable to Enogex LLC	$ 90.0
Add:	
Interest expense, net	30.3
Income tax expense	58.6
Depreciation and amortization expense	71.1
EBITDA	$ 250.0

(A) At the midpoint of Enogex's earnings assumptions for 2010.

For a discussion of the reasons for the use of Ongoing Earnings, Ongoing EPS and EBITDA, as well as their limitations as analytical tools, see "Non-GAAP Financial Measures" below.

Results of Operations

The following discussion and analysis presents factors that affected the Company's consolidated results of operations for the three and nine months ended September 30, 2010 as compared to the same periods in 2009 and the Company's consolidated financial position at September 30, 2010. Due to seasonal fluctuations and other factors, the operating results for the three and nine months ended September 30, 2010 are not necessarily indicative of the results that may be expected for the year ending December 31, 2010 or for any future period. The following information should be read in conjunction with the Condensed Consolidated Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2010	2009	2010	2009
Operating income	$ 274.2	$ 229.7	$ 512.5	$ 408.1
Net income attributable to OGE Energy	$ 163.1	$ 136.8	$ 264.6	$ 224.1
Basic average common shares outstanding	97.4	96.7	97.3	96.0
Diluted average common shares outstanding	99.0	97.7	98.8	96.9
Basic earnings per average common share attributable to				
OGE Energy common shareholders	$ 1.67	$ 1.42	$ 2.72	$ 2.34
Diluted earnings per average common share attributable to				
OGE Energy common shareholders	$ 1.65	$ 1.40	$ 2.68	$ 2.31
Dividends declared per common share	$ 0.3625	$0.3550	$ 1.0875	$ 1.0650

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

Operating Income (Loss) by Business Segment

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010	2009	2010	2009
OG&E (Electric Utility)	$ 231.0	$ 193.2	$ 375.9	$ 308.5
Enogex (Natural Gas Pipeline)				
Transportation and storage	18.6	26.0	58.0	71.2
Gathering and processing	28.2	15.9	89.7	35.1
OERI (Natural Gas Marketing)	(3.0)	(5.8)	(10.5)	(6.3)
Other Operations (A)	(0.6)	0.4	(0.6)	(0.4)
Consolidated operating income	$ 274.2	$ 229.7	$ 512.5	$ 408.1

(A) Other Operations primarily includes the operations of the holding company 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 (Electric Utility)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Dollars in millions)	2010	2009	2010	2009
Operating revenues	$ 723.0	$ 577.9	$ 1,679.8	$ 1,339.9
Cost of goods sold	311.2	235.7	792.8	595.0
Gross margin on revenues	411.8	342.2	887.0	744.9
Other operation and maintenance	110.8	85.7	305.9	248.9
Depreciation and amortization	53.1	47.3	153.4	139.1
Taxes other than income	16.9	16.0	51.8	48.4
Operating income	231.0	193.2	375.9	308.5
Interest income	0.1	0.2	0.1	1.0
Allowance for equity funds used during construction	2.6	5.5	7.2	10.7
Other income (loss)	(1.1)	5.9	2.2	14.7
Other expense	0.4	1.3	1.4	2.5
Interest expense	27.4	22.8	76.8	70.3
Income tax expense	62.7	57.5	103.9	81.2
Net income	$ 142.1	$ 123.2	$ 203.3	$ 180.9
Operating revenues by classification				
Residential	$ 330.9	$ 253.4	$ 729.8	$ 557.3
Commercial	176.5	144.4	409.5	336.1
Industrial	66.2	52.5	164.5	128.3
Oilfield	49.6	38.4	125.6	100.5
Public authorities and street light	67.8	54.0	157.8	126.8
Sales for resale	19.3	15.3	50.5	40.0
Provision for rate refund	(0.4)	---	(0.4)	(0.6)
System sales revenues	709.9	558.0	1,637.3	1,288.4
Off-system sales revenues (A)	5.8	11.1	19.7	25.6
Other	7.3	8.8	22.8	25.9
Total operating revenues	$ 723.0	$ 577.9	$ 1,679.8	$ 1,339.9
MWH (B) sales by classification (in millions)				
Residential	3.218	2.712	7.644	6.812
Commercial	1.970	1.773	5.133	4.873
Industrial	1.034	0.967	2.891	2.667
Oilfield	0.800	0.782	2.281	2.182
Public authorities and street light	0.898	0.826	2.324	2.226
Sales for resale	0.397	0.385	1.076	0.985
System sales	8.317	7.445	21.349	19.745
Off-system sales	0.142	0.350	0.481	0.850
Total sales	8.459	7.795	21.830	20.595
Number of customers	782,174	775,863	782,174	775,863
Average cost of energy per KWH (C) – cents				
Natural gas	4.546	3.468	4.838	3.497
Coal	1.951	1.886	1.891	1.737
Total fuel	3.084	2.575	3.063	2.394

Total fuel and purchased power	3.407	2.803	3.361	2.677
Degree days (D)				
Heating - Actual	7	17	2,305	1,946
Heating - Normal	29	29	2,228	2,228
Cooling - Actual	1,541	1,189	2,286	1,849
Cooling - Normal	1,295	1,295	1,850	1,850

(A) Sales to other utilities and power marketers.
(B) Megawatt-hour.
(C) Kilowatt-hour.
(D) 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.

Three Months Ended September 30, 2010 as Compared to Three Months Ended September 30, 2009

Operating Income

OG&E's operating income increased $37.8 million, or 19.6 percent, during the three months ended September 30, 2010 as compared to the same period in 2009 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense and higher depreciation and amortization expense as discussed below.

Gross Margin

Gross margin was $411.8 million during the three months ended September 30, 2010 as compared to $342.2 million during the same period in 2009, an increase of $69.6 million, or 20.3 percent. The gross margin increased primarily due to:

- warmer weather in OG&E's service territory, which increased the gross margin by $33.3 million;
- increased price variance, which included revenues from various rate riders, including the Windspeed rider, the OU Spirit rider and the Smart Grid rider, and higher revenues from the sales and customer mix, which increased the gross margin by $25.1 million;
- revenues from the Oklahoma rate increase, which increased the gross margin by $5.2 million;
- higher demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by $4.5 million; and
- new customer growth in OG&E's service territory, which increased the gross margin by $2.9 million.

These increases in the gross margin were partially offset by lower other revenues due to fewer transmission requests from others on OG&E's system, which decreased the gross margin by $1.4 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $241.0 million during the three months ended September 30, 2010 as compared to $189.5 million during the same period in 2009, an increase of $51.5 million, or 27.2 percent, primarily due to higher natural gas prices and increased natural gas generation due to ongoing maintenance at some of OG&E's coal-fired power plants. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for the Company and its customers. Purchased power costs were $69.8 million during the three months ended September 30, 2010 as compared to $45.8 million during the same period in 2009, an increase of $24.0 million, or 52.4 percent, primarily due to an increase in purchases in the energy imbalance service market to meet OG&E's generation load requirements and an increase in short-term power agreements resulting in short-term spot market purchases.

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 fuel adjustment clauses. The 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.

Operating Expenses

Other operation and maintenance expenses were $110.8 million during the three months ended September 30, 2010 as compared to $85.7 million during the same period in 2009, an increase of $25.1 million, or 29.3 percent. The increase in other operation and maintenance expenses was primarily due to:

- an increase of $4.2 million in other marketing and sales expense related to demand-side management initiatives, which expenses are being recovered through a rider;
- an increase of $3.6 million in contract technical and construction services expense and an increase of $1.3 million in materials and supplies expense primarily attributable to increased spending for ongoing maintenance at some of OG&E's power plants in the third quarter of 2010 as compared to the same period in 2009;
- an increase of $3.5 million in employee benefits expense primarily due to an increase in postretirement benefits due to an increase in medical costs and changes in actuarial assumptions in 2010;
- an increase of $2.8 million in activity costs related to less work being capitalized in the third quarter of 2010;
- an increase of $2.4 million in salaries and wages expense primarily due to salary increases in 2010;

- Ÿan increase of $2.3 million in injuries and damages expense primarily due to increased reserves on claims in the third quarter of 2010;
- Ÿ an increase of $1.8 million in allocations from the holding company; and
- Ÿan increase of $1.4 million due to increased spending on vegetation management related to system hardening, which expenses are being recovered through a rider.

These increases in other operation and maintenance expenses were partially offset by a decrease of $1.4 million in incentive compensation expense primarily due to lower accruals in the third quarter of 2010.

Depreciation and amortization expense was $53.1 million during the three months ended September 30, 2010 as compared to $47.3 million during the same period in 2009, an increase of $5.8 million, or 12.3 percent, primarily due to additional assets being placed into service, including OU Spirit that was placed into service in November and December 2009 and the Windspeed transmission line that was placed into service on March 31, 2010.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for Equity Funds Used During Construction ("AEFUDC") was $2.6 million during the three months ended September 30, 2010 as compared to $5.5 million during the same period in 2009, a decrease of $2.9 million, or 52.7 percent, primarily due to the completion of OU Spirit in November and December 2009 and the Windspeed transmission line on March 31, 2010.

Other Income (Loss). Other loss was $1.1 million during the three months ended September 30, 2010 as compared to other income of $5.9 million during the same period in 2009, a decrease in other income of $7.0 million. The decrease in other income was primarily due to:

- Ÿa decrease of $4.8 million due to a decreased level of gains recognized in the guaranteed flat bill program during the third quarter of 2010 from higher than expected usage resulting from warmer weather in addition to more customers participating in the guaranteed flat bill program during the third quarter of 2010; and
- Ÿ a decrease of $1.9 million related to the benefit associated with the tax gross-up of AEFUDC.

Interest Expense. Interest expense was $27.4 million during the three months ended September 30, 2010 as compared to $22.8 million during the same period in 2009, an increase of $4.6 million, or 20.2 percent, primarily due to a $3.7 million increase related to the issuance of $250 million of long-term debt in June 2010 and a $1.6 million increase due to a lower allowance for borrowed funds used during construction during the third quarter of 2010 as compared to the same period in 2009.

Income Tax Expense. Income tax expense was $62.7 million during the three months ended September 30, 2010 as compared to $57.5 million during the same period in 2009, an increase of $5.2 million, or 9.0 percent, primarily due to higher pre-tax income during the three months ended September 30, 2010 as compared to the same period in 2009 partially offset by an increase in Federal renewable energy credits during the three months ended September 30, 2010 as compared to the same period in 2009.

Nine Months Ended September 30, 2010 as Compared to Nine Months Ended September 30, 2009

Operating Income

OG&E's operating income increased $67.4 million, or 21.8 percent, during the nine months ended September 30, 2010 as compared to the same period in 2009 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense, higher depreciation and amortization expense and higher taxes other than income as discussed below.

Gross Margin

Gross margin was $887.0 million during the nine months ended September 30, 2010 as compared to $744.9 million during the same period in 2009, an increase of $142.1 million, or 19.1 percent. The gross margin increased primarily due to:

- Ÿ increased price variance, which included revenues from various rate riders, including the Windspeed rider, the OU Spirit rider and the Smart Grid rider, and higher revenues from the sales and customer mix, which increased the gross margin by $61.4 million;
- Ÿ warmer weather in OG&E's service territory, which increased the gross margin by $46.7 million;

- Ÿ revenue from the Oklahoma rate increase, which increased the gross margin by $24.1 million;
- Ÿ new customer growth in OG&E's service territory, which increased the gross margin by $5.9 million;
- Ÿ higher demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by $4.5 million; and
- Ÿ revenues from the Arkansas rate increase, which increased the gross margin by $3.5 million.

These increases in the gross margin were partially offset by lower other revenues due to fewer transmission requests from others on OG&E's system, which decreased the gross margin by $4.0 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $622.4 million during the nine months ended September 30, 2010 as compared to $467.7 million during the same period in 2009, an increase of $154.7 million, or 33.1 percent, primarily due to higher natural gas prices and increased natural gas generation due to ongoing maintenance at some of OG&E's coal-fired power plants. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for the Company and its customers. Purchased power costs were $168.6 million during the nine months ended September 30, 2010 as compared to $125.8 million during the same period in 2009, an increase of $42.8 million, or 34.0 percent, primarily due to an increase in purchases in the energy imbalance service market to meet OG&E's generation load requirements and an increase in short-term power agreements resulting in short-term spot market purchases.

Operating Expenses

Other operation and maintenance expenses were $305.9 million during the nine months ended September 30, 2010 as compared to $248.9 million during the same period in 2009, an increase of $57.0 million, or 22.9 percent. The increase in other operation and maintenance expenses was primarily due to:

- Ÿ an increase of $15.1 million in contract technical and construction services and an increase of $1.9 million in materials and supplies expense primarily attributable to increased spending for ongoing maintenance at some of OG&E's power plants during the nine months ended September 30, 2010 as compared to the same period in 2009;
- Ÿ an increase of $13.5 million in employee benefits expense primarily due to an increase in postretirement benefits due to an increase in medical costs and changes in actuarial assumptions in 2010, a reclassification in May 2009 of 2006 and 2007 pension settlement costs to a regulatory asset, as prescribed in the Arkansas rate case settlement, and an increase in pension expense due to an increase in the amount deferred as a pension regulatory liability in OG&E's Oklahoma jurisdiction resulting from OG&E's 2009 Oklahoma rate case;
- Ÿ an increase of $7.3 million in salaries and wages expense primarily due to salary increases in 2010;
- Ÿ an increase of $5.4 million in other marketing and sales expense related to demand-side management initiatives, which expenses are being recovered through a rider;
- Ÿ an increase of $4.0 million in injuries and damages expense primarily due to increased reserves on claims during the nine months ended September 30, 2010;
- Ÿ an increase of $3.8 million due to increased spending on vegetation management related to system hardening, which expenses are being recovered through a rider;
- Ÿ an increase of $2.8 million in allocations from the holding company; and
- Ÿ an increase of $1.6 million in overtime expense due to the storms in January and May 2010.

These increases in other operation and maintenance expenses were partially offset by a decrease of $2.0 million in incentive compensation expense primarily due to lower accruals during the nine months ended September 30, 2010.

Depreciation and amortization expense was $153.4 million during the nine months ended September 30, 2010 as compared to $139.1 million during the same period in 2009, an increase of $14.3 million, or 10.3 percent, primarily due to additional assets being placed into service, including OU Spirit that was placed into service in November and

December 2009 and the Windspeed transmission line that was placed into service on March 31, 2010.

Additional Information

Allowance for Equity Funds Used During Construction. AEFUDC was $7.2 million during the nine months ended September 30, 2010 as compared to $10.7 million during the same period in 2009, a decrease of $3.5 million or 32.7 percent, primarily due to the completion of OU Spirit in November and December 2009 and the Windspeed transmission line on March 31, 2010.

Other Income. Other income was $2.2 million during the nine months ended September 30, 2010 as compared to $14.7 million during the same period in 2009, a decrease in other income of $12.5 million, or 85.0 percent. The decrease in other income was primarily due to:

- Ÿ a decrease of $9.3 million due to a decreased level of gains recognized in the guaranteed flat bill program during the nine months ended September 30, 2010 from higher than expected usage resulting from warmer weather in addition to more customers participating in the guaranteed flat bill program during the nine months ended September 30, 2010; and
- Ÿ a decrease of $2.4 million related to the benefit associated with the tax gross-up of AEFUDC.

Interest Expense. Interest expense was $76.8 million during the nine months ended September 30, 2010 as compared to $70.3 million during the same period in 2009, an increase of $6.5 million, or 9.2 percent, primarily due to a $4.6 million increase related to the issuance of $250 million of long-term debt in June 2010 and a $2.4 million increase due to a lower allowance for borrowed funds used during construction during the nine months ended September 30, 2010 as compared to the same period in 2009.

Income Tax Expense. Income tax expense was $103.9 million during the nine months ended September 30, 2010 as compared to $81.2 million during the same period in 2009, an increase of $22.7 million, or 28.0 percent, primarily due to:

- Ÿ higher pre-tax income during the nine months ended September 30, 2010 as compared to the same period in 2009;
- Ÿ an adjustment for the elimination of the tax deduction for the Medicare Part D subsidy (discussed in Note 7 of Notes to Condensed Consolidated Financial Statements); and
- Ÿ the write-off of previously recognized Oklahoma investment tax credits primarily due to expenditures no longer eligible for the Oklahoma investment tax credit related to the change in the tax method of accounting for capitalization of repair expenditures.

These increases in income tax expense were partially offset by an increase in Federal renewable energy credits during the nine months ended September 30, 2010 as compared to the same period in 2009.

Enogex (Natural Gas Transportation and Storage and Natural Gas Gathering and Processing)

Three Months Ended September 30, 2010	Transportation and Storage	Gathering and Processing	Eliminations	Total
(In millions)				
Operating revenues	$ 103.5	$ 243.1	$ (67.7)	$ 278.9
Cost of goods sold	64.8	178.9	(67.7)	176.0
Gross margin on revenues	38.7	64.2	---	102.9
Other operation and maintenance	11.6	22.0	---	33.6
Depreciation and amortization	5.2	12.6	---	17.8
Taxes other than income	3.3	1.4	---	4.7
Operating income	$ 18.6	$ 28.2	$ ---	$ 46.8

Three Months Ended	Transportation and	Gathering and

September 30, 2009 (In millions)	Storage	Processing	Eliminations	Total
Operating revenues	$ 91.5	$ 156.1	$ (36.9)	$ 210.7
Cost of goods sold	47.4	107.3	(36.9)	117.8
Gross margin on revenues	44.1	48.8	---	92.9
Other operation and maintenance	9.8	19.6	---	29.4
Depreciation and amortization	5.2	11.9	---	17.1
Taxes other than income	3.1	1.4	---	4.5
Operating income	$ 26.0	$ 15.9	$ ---	$ 41.9

Nine Months Ended September 30, 2010	Transportation and Storage	Gathering and Processing	Eliminations	Total
(In millions)				
Operating revenues	$ 311.7	$ 726.4	$ (205.0)	$ 833.1
Cost of goods sold	191.9	527.5	(205.0)	514.4
Gross margin on revenues	119.8	198.9	---	318.7
Other operation and maintenance	35.2	66.8	---	102.0
Depreciation and amortization	16.0	37.5	---	53.5
Taxes other than income	10.6	4.9	---	15.5
Operating income	$ 58.0	$ 89.7	$ ---	$ 147.7

Nine Months Ended September 30, 2009	Transportation and Storage	Gathering and Processing	Eliminations	Total
(In millions)				
Operating revenues	$ 300.8	$ 436.9	$ (146.0)	$ 591.7
Cost of goods sold	174.3	302.1	(146.0)	330.4
Gross margin on revenues	126.5	134.8	---	261.3
Other operation and maintenance	29.4	62.6	---	92.0
Depreciation and amortization	16.0	32.9	---	48.9
Taxes other than income	9.9	4.2	---	14.1
Operating income	$ 71.2	$ 35.1	$ ---	$ 106.3

Operating Data

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Gathered volumes – TBtu/d (A)	1.34	1.27	1.32	1.25
Incremental transportation volumes – TBtu/d (B)	0.46	0.66	0.44	0.55
Total throughput volumes – TBtu/d	1.80	1.93	1.76	1.80
Natural gas processed – TBtu/d	0.86	0.74	0.81	0.69
NGLs sold (keep-whole) – million gallons	44	21	137	69
NGLs sold (purchased for resale) – million gallons	119	100	339	254
NGLs sold (percent-of-liquids) – million gallons	8	8	22	25
Total NGLs sold – million gallons	171	129	498	348
Average sales price per gallon	$ 0.92	$ 0.74	$ 0.94	$ 0.68
Estimated realized keep-whole spreads (C)	$ 5.28	$ 3.73	$ 5.24	$ 3.40

(A) Trillion British thermal units per day (“TBtu/d”).

(B) Incremental transportation volumes consist of natural gas moved only on the transportation pipeline.

(C) The estimated realized keep-whole spread is an approximation of the spread between the weighted-average sales price of the retained NGLs commodities and the purchase price of the replacement natural gas shrink. The spread is based on the market commodity spread less any gains or losses realized from keep-whole hedging transactions. The market commodity spread is estimated using the average of the Oil Price Information Service daily average posting at the Conway, Kansas market for the NGLs and the Inside FERC monthly index posting for Panhandle Eastern Pipe Line Co., Texas, Oklahoma, for the forward month contract for natural gas prices.

Three Months Ended September 30, 2010 as Compared to Three Months Ended September 30, 2009

Operating Income

Enogex's operating income increased $4.9 million, or 11.7 percent, during the three months ended September 30, 2010 as compared to the same period in 2009. This increase was primarily due to higher processing spreads, higher NGLs prices, higher natural gas prices, increased volumes and higher gallons per million cubic foot ("GPM") of natural gas associated with expansion projects. Additionally, the fourth quarter 2009 addition of the new higher efficiency Clinton processing plant enabled Enogex to optimize recoveries across all processing plants. In the normal course of Enogex's business, the operation of its gathering, processing and transportation assets results in the creation of physical natural gas long/short positions. These physical positions can result from gas imbalances, actual versus contractual settlement differences, fuel tracker obligations and natural gas received in-kind for compensation or reimbursements. Enogex actively manages its monthly net position through either selling excess gas or purchasing additional gas needs from third parties through OERI. During the three months ended September 30, 2010, volume changes and realized margin on physical gas long/short positions decreased the gross margin by $1.9 million, net of corresponding imbalance and fuel tracker obligations.

Operation and maintenance expense increased $4.2 million, or 14.3 percent, primarily due to salary increases in 2010, an increase in non-capitalized project costs, increased costs related to pipeline integrity assessments and the reversal of a reserve during the third quarter of 2009 related to the dismissal of the Grynberg case as discussed in Note 13 of Notes to Consolidated Financial Statements in the Company's 2009 Form 10-K partially offset by the recognition of an insurance reimbursement related to the November 2008 pipeline rupture as discussed in Note 13 of Notes to the Condensed Consolidated Financial Statements and lower allocations from the holding company.

Transportation and Storage

The transportation and storage business contributed $38.7 million of Enogex's consolidated gross margin during the three months ended September 30, 2010 as compared to $44.1 million in the same period in 2009, a decrease of $5.4 million, or 12.2 percent. The transportation operations contributed $31.0 million of Enogex's consolidated gross margin during the three months ended September 30, 2010 as compared to $35.7 million in the same period in 2009. The storage operations contributed $7.7 million of Enogex's consolidated gross margin during the three months ended September 30, 2010 as compared to $8.4 million in the same period in 2009. The transportation and storage gross margin decreased primarily due to the reduction of volumes transported under the Midcontinent Express Pipeline, LLC ("MEP") and Gulf Crossing capacity leases and Section 311 firm East side service due to pipeline integrity work on an Enogex pipeline in 2010, which decreased the gross margin by $4.7 million.

Operation and maintenance expense for the transportation and storage business was $1.8 million, or 18.4 percent, higher during the three months ended September 30, 2010 as compared to the same period in 2009 primarily due to salary increases in 2010, increased costs related to pipeline integrity assessments and the reversal of a $1.5 million reserve during the third quarter of 2009 related to the dismissal of the Grynberg case as discussed in Note 13 of Notes to Consolidated Financial Statements in the Company's 2009 Form 10-K partially offset by lower allocations from the holding company.

Gathering and Processing

The gathering and processing business contributed $64.2 million of Enogex's consolidated gross margin during the three months ended September 30, 2010 as compared to $48.8 million in the same period in 2009, an increase of $15.4 million, or 31.6 percent. The gathering operations contributed $29.3 million of Enogex's consolidated gross margin during the three months ended September 30, 2010 as compared to $30.2 million in the same period in 2009. The processing operations contributed $34.9 million of Enogex's consolidated gross margin during the three months ended September 30, 2010 as compared to $18.6 million in the same period in 2009.

During the three months ended September 30, 2010, Enogex realized a higher gross margin in its gathering and processing operations primarily as the result of continued growth in gathered volumes, higher processing spreads, higher NGLs prices and higher natural gas prices, net of Enogex's continued effort to convert customers from keep-whole to fixed-fee processing arrangements. Enogex's processing plants saw a 16.1 percent increase in inlet volumes, an increase in NGLs production as recent expansion projects have added richer natural gas to Enogex's system and the fourth quarter 2009 completion of the new higher efficiency Clinton processing plant allowed Enogex to optimize recoveries across all processing plants. Overall, the above factors resulted in the following:

- increased gross margin on keep-whole processing of $10.6 million;
- increased fixed processing fees of $3.0 million; and
- increased gross margin on NGLs retained under percent-of-liquids (“POL”) contracts of $2.8 million.

Another factor that contributed to the increase in the gathering and processing gross margin was an increase in condensate revenues associated with the gathering and processing operations due to increased volumes as a result of several new expansion projects with higher GPM of natural gas and higher condensate prices, which increased the gross margin by $1.1 million.

These increases in the gathering and processing gross margin were partially offset by lower volumes and realized margin on sales of physical natural gas long/short positions associated with gathering operations, which decreased the gross margin by $1.9 million, net of imbalance and fuel tracker obligations.

Other operation and maintenance expense for the gathering and processing business was $2.4 million, or 12.2 percent, higher during the three months ended September 30, 2010 as compared to the same period in 2009 primarily due to an increase in non-capitalized project costs partially offset by the recognition of an insurance reimbursement related to the November 2008 pipeline rupture as discussed in Note 13 of Notes to the Condensed Consolidated Financial Statements.

Enogex Consolidated Information

Interest Expense. Enogex’s consolidated interest expense was $7.2 million during the three months ended September 30, 2010 as compared to $12.1 million during the same period in 2009, a decrease of $4.9 million, or 40.5 percent, primarily due to:

- Ÿ $2.8 million tender payment on the tender offer Enogex completed in July 2009 related to the retirement of $110.8 million of senior notes; and
- Ÿ decrease of $2.7 million in interest expense during the three months ended September 30, 2010 as compared to the same period in 2009 due to a lower interest rate on long-term debt issued in 2009 as compared to the interest rate on long-term debt that was retired in January 2010.

These decreases in interest expense were partially offset by a decrease of $0.9 million in capitalized interest related to lower capital expenditures and fewer projects qualifying for capitalized interest during the three months ended September 30, 2010 as compared to the same period in 2009.

Income Tax Expense. Enogex’s consolidated income tax expense was $15.0 million during the three months ended September 30, 2010 as compared to $10.7 million during the same period in 2009, an increase of $4.3 million, or 40.2 percent, primarily due to higher pre-tax income in the third quarter of 2010 as compared to the same period in 2009.

Non-recurring Items. Enogex had net income of $24.2 million during the three months ended September 30, 2010, which does not include any items that Enogex does not consider to be reflective of its ongoing operations.

Enogex had net income of $18.1 million for the three months ended September 30, 2009, which includes a net loss of $0.8 million for items the Company does not consider to be reflective of its ongoing operations. This decrease in Enogex’s consolidated net income included a tender payment on the tender offer Enogex completed in July 2009 of $1.7 million after-tax related to the retirement of $110.8 million of senior notes, which was a portion of Enogex’s 8.125% senior notes that matured in January 2010 partially offset by the reversal of a reserve of $0.9 million after-tax during the three months ended September 30, 2009 related to the dismissal of the Grynberg case as discussed in Note 13 of Notes to Consolidated Financial Statements in the Company’s 2009 Form 10-K.

Nine Months Ended September 30, 2010 as Compared to Nine Months Ended September 30, 2009

Operating Income

Enogex's operating income increased $41.4 million, or 38.9 percent, during the nine months ended September 30, 2010 as compared to the same period in 2009. This increase was primarily due to higher processing spreads, higher NGLs prices, higher natural gas prices, increased volumes and higher GPM of natural gas associated with expansion projects. Additionally, the fourth quarter 2009 addition of the new higher efficiency Clinton processing plant enabled Enogex to optimize recoveries across all processing plants. In the normal course of Enogex's business, the operation of its gathering, processing and transportation assets results in the creation of physical natural gas long/short positions. These physical positions can result from gas imbalances, actual versus contractual settlement differences, fuel tracker obligations and natural gas received in-kind for compensation or reimbursements. Enogex actively manages its monthly net position through either selling excess gas or purchasing additional gas needs from third parties through OERI. During the nine months ended September 30, 2010, volume changes and realized margin on physical gas long/short positions increased the gross margin by $1.2 million, net of corresponding imbalance and fuel tracker obligations.

Operation and maintenance expense increased $10.0 million, or 10.9 percent, primarily due to salary increases in 2010, increased costs related to pipeline integrity assessments, the reversal of a reserve during the third quarter of 2009 related to the dismissal of the Grynberg case as discussed in Note 13 of Notes to Consolidated Financial Statements in the Company's 2009 Form 10-K and increased costs associated with the settlement of the November 2008 pipeline rupture partially offset by the recognition of a related insurance reimbursement as discussed in Note 13 of Notes to the Condensed Consolidated Financial Statements and a decrease in non-capitalized project costs.

Depreciation and amortization expense increased $4.6 million, or 9.4 percent, primarily due to additional assets placed into service in 2009 and during the nine months ended September 30, 2010.

Taxes other than income increased $1.4 million, or 9.9 percent, primarily due to an increase in ad valorem tax expense as a result of assets placed into service in 2009.

Transportation and Storage

The transportation and storage business contributed $119.8 million of Enogex's consolidated gross margin during the nine months ended September 30, 2010 as compared to $126.5 million in the same period in 2009, a decrease of $6.7 million, or 5.3 percent. The transportation operations contributed $95.3 million of Enogex's consolidated gross margin during the nine months ended September 30, 2010 as compared to $104.1 million in the same period in 2009. The storage operations contributed $24.5 million of Enogex's consolidated gross margin during the nine months ended September 30, 2010 as compared to $22.4 million in the same period in 2009. The transportation and storage gross margin decreased primarily due to:

- lower crosshaul volumes as fewer customers moved natural gas to eastern markets during the nine months ended September 30, 2010 as there were smaller differences in natural gas prices at various U.S. market locations partially offset by customers utilizing crosshaul services due to pipeline integrity work on an Enogex pipeline, which decreased the gross margin by $7.3 million;
- An increase in the imbalance liability, net of fuel recoveries and natural gas length positions, which decreased the gross margin by $2.4 million;
- lower realized margins on operational storage hedges as the result of lower transacted volumes during the nine months ended September 30, 2010 as compared to the same period in 2009, which decreased the gross margin by $2.3 million;
- decreased low/high pressure revenues due to customers shipping production through the firm capacity leases and Section 311 firm East side service, which decreased the gross margin by $1.5 million; and
- lower storage fees due to a reduction in the market value of storage capacity, which decreased the gross margin by $1.1 million.

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

- No adjustment of natural gas storage inventory during the nine months ended September 30, 2010 as compared to $5.8 million lower of cost or market adjustment to the natural gas storage inventory during the nine months ended September 30, 2009 due to lower natural gas prices; and
- capacity lease service under the MEP and Gulf Crossing capacity leases that were placed into service in June 2009 partially offset by the reduction due to pipeline integrity work on an Enogex pipeline in 2010 increased transportation fees by $2.8 million.

Operation and maintenance expense for the transportation and storage business was $5.8 million, or 19.7 percent, higher during the nine months ended September 30, 2010 as compared to the same period in 2009 primarily due to salary increases in 2010, increased costs related to pipeline integrity assessments and the reversal of a $1.5 million reserve during the third quarter of 2009 related to the dismissal of the Grynberg case as discussed in Note 13 of Notes to Consolidated Financial Statements in the Company's 2009 Form 10-K.

Gathering and Processing

The gathering and processing business contributed $198.9 million of Enogex's consolidated gross margin during the nine months ended September 30, 2010 as compared to $134.8 million in the same period in 2009, an increase of $64.1 million, or 47.6 percent. The gathering operations contributed $88.5 million of Enogex's consolidated gross margin during the nine months ended September 30, 2010 as compared to $81.6 million in the same period in 2009. The processing operations contributed $110.4 million of Enogex's consolidated gross margin during the nine months ended September 30, 2010 as compared to $53.2 million in the same period in 2009.

During the nine months ended September 30, 2010, Enogex realized a higher gross margin in its gathering and processing operations primarily as the result of continued growth in gathered volumes, higher processing spreads, higher NGLs prices and higher natural gas prices, net of Enogex's continued effort to convert customers from keep-whole to fixed-fee processing arrangements. Enogex's processing plants saw a 17.0 percent increase in inlet volumes, an increase in NGLs production as recent expansion projects have added richer natural gas to Enogex's system and the fourth quarter 2009 completion of the new higher efficiency Clinton processing plant allowed Enogex to optimize recoveries across all processing plants. Overall, the above factors resulted in the following:

- increased gross margin on keep-whole processing of $28.5 million;
- increased fixed processing fees of $11.2 million; and
- increased gross margin on NGLs retained under POL contracts of $9.4 million.

Other factors that contributed to the increase in the gathering and processing gross margin were:

- An increase in condensate revenues associated with the gathering and processing operations as a result of cooler weather in the first quarter of 2010 and increased volumes as a result of several new expansion projects with higher GPM of natural gas and higher condensate prices, which increased the gross margin by $10.2 million;
- Higher volumes and realized margin on sales of physical natural gas long/short positions associated with gathering operations, which increased the gross margin by $3.6 million, net of imbalance and fuel tracker obligations; and
- Increased gathered volumes associated with expansion projects, which increased the gathering fees by $2.7 million.

These increases in the gathering and processing gross margin were partially offset by increased processing fees associated with natural gas from Enogex's Atoka natural gas processing plant being processed at a third-party processing plant, which decreased the gross margin by $1.1 million.

Other operation and maintenance expense for the gathering and processing business was $4.2 million, or 6.7 percent, higher during the nine months ended September 30, 2010 as compared to the same period in 2009 primarily due to increased costs associated with the settlement of the November 2008 pipeline rupture partially offset by the recognition of a related insurance reimbursement as discussed in Note 13 of Notes to the Condensed Consolidated Financial Statements and a decrease in non-capitalized project costs.

Enogex Consolidated Information

Interest Expense. Enogex's consolidated interest expense was $22.6 million during the nine months ended September 30, 2010 as compared to $24.4 million during the same period in 2009, a decrease of $1.8 million, or 7.3 percent, primarily due to:

- A decrease of $3.2 million in interest expense during the nine months ended September 30, 2010 as compared to the same period in 2009 due to a lower interest rate on long-term debt issued in 2009 as compared to the interest rate on long-term debt that was retired in January 2010; and
- A $2.8 million tender payment on the tender offer Enogex completed in July 2009 related to the retirement of $110.8 million of senior notes.

These decreases in interest expense were partially offset by a decrease of $4.5 million in capitalized interest related to lower capital expenditures and fewer projects qualifying for capitalized interest during the nine months ended September 30, 2010 as compared to the same period in 2009.

Income Tax Expense. Enogex's consolidated income tax expense was $49.2 million during the nine months ended September 30, 2010 as compared to $30.2 million during the same period in 2009, an increase of $19.0 million, or 62.9 percent, primarily due to higher pre-tax income during the nine months ended September 30, 2010 as compared to the same period in 2009 and an adjustment for the elimination of the tax deduction for the Medicare Part D subsidy (discussed in Note 7 of Notes to Condensed Consolidated Financial Statements).

Non-recurring Items. Enogex had net income of $73.9 million during the nine months ended September 30, 2010, which does not include any items that Enogex does not consider to be reflective of its ongoing operations.

Enogex had net income of $49.5 million for the nine months ended September 30, 2009, which includes a net loss of $0.8 million for items the Company does not consider to be reflective of its ongoing operations. This decrease in Enogex's consolidated net income included a tender payment on the tender offer Enogex completed in July 2009 of $1.7 million after-tax related to the retirement of $110.8 million of senior notes, which was a portion of Enogex's 8.125% senior notes that matured in January 2010 partially offset by the reversal of a reserve of $0.9 million after-tax during the nine months ended September 30, 2009 related to the dismissal of the Grynberg case as discussed in Note 13 of Notes to Consolidated Financial Statements in the Company's 2009 Form 10-K.

OERI (Natural Gas Marketing)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
(In millions)				
Operating revenues	$ 206.5	$ 127.2	$ 641.2	$ 436.7
Cost of goods sold	207.6	130.5	644.8	434.9
Gross margin on revenues	(1.1)	(3.3)	(3.6)	1.8
Other operation and maintenance	1.8	2.5	6.6	7.8
Taxes other than income	0.1	---	0.3	0.3
Operating loss	$ (3.0)	$ (5.8)	$ (10.5)	$ (6.3)

Three Months Ended September 30, 2010 as Compared to Three Months Ended September 30, 2009

Operating Loss

OERI's operating loss was $3.0 million during the three months ended September 30, 2010 as compared to $5.8 million during the same period in 2009, a decrease in the operating loss of $2.8 million, or 48.3 percent, primarily due to a lower gross margin loss as discussed below.

Gross Margin

Gross margin was a loss of $1.1 million during the three months ended September 30, 2010 as compared to a loss of $3.3 million during the same period in 2009, a decrease in the gross margin loss of $2.2 million, or 66.7 percent, primarily due to mark-to-market storage hedge gains during the third quarter of 2010 as compared to mark-to-market storage hedge losses during the third quarter of 2009, which increased the gross margin by $1.5 million.

Additional Information

Income Tax Benefit. Income tax benefit was $1.2 million during the three months ended September 30, 2010 as compared to $2.3 million during the same period in 2009, a decrease of $1.1 million, or 47.8 percent, primarily due to a lower pre-tax loss during the three months ended September 30, 2010 as compared to the same period in 2009.

Nine Months Ended September 30, 2010 as Compared to Nine Months Ended September 30, 2009

Operating Loss

OERI's operating loss was $10.5 million during the nine months ended September 30, 2010 as compared to $6.3 million during the same period in 2009, an increase in the operating loss of $4.2 million, or 66.7 percent, primarily due to a lower gross margin as discussed below.

Gross Margin

Gross margin was a loss of $3.6 million during the nine months ended September 30, 2010 as compared to a gain of $1.8 million during the same period in 2009, a decrease in the gross margin of $5.4 million, primarily due to smaller differences in natural gas prices at various U.S. market locations which resulted in a reduced spread that OERI was able to realize from delivering gas under its transportation contracts, which decreased the gross margin from transportation by $5.4 million.

Operating Expenses

Other operation and maintenance expenses were $6.6 million during the nine months ended September 30, 2010 as compared to $7.8 million during the same period in 2009, a decrease of $1.2 million, or 15.4 percent, primarily due to lower allocations from Enogex and lower incentive compensation expense primarily due to lower accruals during the nine months ended September 30, 2010.

Additional Information

Income Tax Benefit. Income tax benefit was $4.3 million during the nine months ended September 30, 2010 as compared to $2.6 million during the same period in 2009, an increase of $1.7 million, or 65.4 percent, primarily due to a higher pre-tax loss during the nine months ended September 30, 2010 as compared to the same period in 2009.

Non-GAAP Financial Measures

The Company has included in this Form 10-Q the non-GAAP financial measures Ongoing Earnings and Ongoing EPS. The Company defines Ongoing Earnings as GAAP net income less the charge for the Medicare Part D tax subsidy and Ongoing EPS as GAAP EPS less the charge for the Medicare Part D tax subsidy. The Medicare Part D tax subsidy represents a charge which management believes will not be recurring on a regular basis. Management believes that the presentation of Ongoing Earnings and Ongoing EPS provides useful information to investors, as it provides them an additional relevant comparison of the Company's performance across periods.

The Company provides a reconciliation of Ongoing Earnings and Ongoing EPS to its most directly comparable financial measures as calculated and presented in accordance with GAAP. The most directly comparable GAAP measure for Ongoing Earnings is GAAP net income which includes the impact of the charge for the Medicare Part D tax subsidy. The most directly comparable GAAP measure for Ongoing EPS is GAAP EPS which includes the charge for the Medicare Part D tax subsidy. The non-GAAP financial measure of Ongoing Earnings and Ongoing EPS should not be considered as an alternative to GAAP net income attributable to the Company or GAAP EPS. Ongoing Earnings and Ongoing EPS are not a presentation made in accordance with GAAP and have important limitations as analytical tools. They should not be considered in isolation or as a substitute for analysis of the Company's results as reported under GAAP. Because these non-GAAP financial measures exclude some, but not all, items that affect net income and EPS and are defined differently by different companies in the Company's industry, the Company's definition of Ongoing Earnings and Ongoing EPS may not be comparable to a similarly titled measure of other companies.

To compensate for the limitations of these non-GAAP financial measures as analytical tools, the Company believes it is important to review the comparable GAAP measures and understand the differences between the measures.

Reconciliation of Ongoing Earnings (Loss) to GAAP Net Income for the Nine Months Ended September 30, 2010 and 2009

(In millions)	Nine Months Ended September 30, 2010 Ongoing Earnings	Medicare Part D Tax Subsidy	Nine Months Ended September 30, 2010 GAAP Net Income (Loss)	Nine Months Ended September 30, 2009 GAAP and Ongoing Net Income (Loss) (A)
OG&E	$ 210.3	$ (7.0)	$ 203.3	$ 180.9
Enogex	75.9	(2.0)	73.9	49.5
Holding Company	(10.2)	(2.4)	(12.6)	(6.3)

Consolidated	$ 276.0	$ (11.4)	$ 264.6	$ 224.1

(A) There were no one-time charges for the nine months ended September 30, 2009 therefore, ongoing and GAAP net income are the same.

Reconciliation of Ongoing EPS to GAAP EPS for the Nine Months Ended September 30, 2010 and 2009

(In millions)	Nine Months Ended September 30, 2010 Ongoing EPS	Medicare Part D Tax Subsidy	Nine Months Ended September 30, 2010 GAAP EPS	Nine Months Ended September 30, 2009 GAAP and Ongoing EPS (B)
OG&E	$ 2.13	$ (0.07)	$ 2.06	$ 1.87
Enogex	0.77	(0.02)	0.75	0.51
Holding Company	(0.11)	(0.02)	(0.13)	(0.07)
Consolidated	$ 2.79	$ (0.11)	$ 2.68	$ 2.31

(B) There were no one-time charges for the nine months ended September 30, 2009 therefore, ongoing and GAAP EPS are the same.

Enogex has included in this Form 10-Q the non-GAAP financial measure EBITDA. Enogex defines EBITDA as net income attributable to Enogex LLC before interest, income taxes and depreciation and amortization. EBITDA is used as a supplemental financial measure by external users of the Company's financial statements such as investors, commercial banks and others, to assess:

- the financial performance of Enogex's assets without regard to financing methods, capital structure or historical cost basis;
- Enogex's operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Enogex provides a reconciliation of EBITDA to its most directly comparable financial measure as calculated and presented in accordance with GAAP. The GAAP measure most directly comparable to EBITDA is net income attributable to Enogex LLC. The non-GAAP financial measure of EBITDA should not be considered as an alternative to GAAP net income attributable to Enogex LLC. EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. EBITDA should not be considered in isolation or as a substitute for analysis of Enogex's results as reported under GAAP. Because EBITDA excludes some, but not all, items that affect net income and is defined differently by different companies in Enogex's industry, Enogex's definition of EBITDA may not be comparable to a similarly titled measure of other companies.

To compensate for the limitations of EBITDA as an analytical tool, Enogex believes it is important to review the comparable GAAP measure and understand the differences between the measures.

Reconciliation of EBITDA to net income attributable to Enogex LLC

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010	2009	2010	2009
Net income attributable to Enogex LLC	$ 24.2	$ 18.1	$ 73.9	$ 49.5
Add:				
Interest expense, net	7.2	12.1	22.6	24.3
Income tax expense	15.0	10.7	49.2	30.2
Depreciation and amortization expense	17.8	17.1	53.5	48.9
EBITDA	$ 64.2	$ 58.0	$ 199.2	$ 152.9

Financial Condition

The balance of Cash and Cash Equivalents was $8.5 million and $58.1 million at September 30, 2010 and December 31, 2009, respectively, a decrease of $49.6 million, or 85.4 percent. See “Cash Flows” for a discussion of the changes in Cash and Cash Equivalents.

The balance of Accounts Receivable was $339.4 million and $291.4 million at September 30, 2010 and December 31, 2009, respectively, an increase of $48.0 million, or 16.5 percent, primarily due to an increase in billings to OG&E’s

customers reflecting warmer weather in September 2010 as compared to December 2009 partially offset by a decrease in average natural gas prices and volumes at OERI.

The balance of Income Taxes Receivable was $16.5 million and $157.7 million at September 30, 2010 and December 31, 2009, respectively, a decrease of $141.2 million, or 89.5 percent, primarily due to an income tax refund received in February 2010 related to a carry back of the 2008 tax loss resulting from a change in tax method of accounting for capitalization of repair expenditures.

The balance of Construction Work in Progress was $405.5 million and $335.4 million at September 30, 2010 and December 31, 2009, respectively, an increase of $70.1 million, or 20.9 percent, primarily due to increased spending on various distribution, transmission and generation projects, including Crossroads, at OG&E as well as increases from the purchase of compressors and a natural gas processing plant at Enogex partially offset by the costs associated with the Windspeed transmission line constructed by OG&E which was placed in service on March 31, 2010 being reclassified to Property, Plant and Equipment In Service.

The balance of Short-Term Debt was $224.0 million and $175.0 million at September 30, 2010 and December 31, 2009, respectively, an increase of $49.0 million, or 28.0 percent, primarily due to an increase in commercial paper borrowings in the first quarter of 2010 to repay the remaining balance of Enogex's $400 million 8.125% senior notes which matured on January 15, 2010 and an increase due to daily operational needs partially offset by a decrease in commercial paper borrowings during the nine months ended September 30, 2010 due to OG&E's issuance of $250 million in long-term debt in June 2010.

The balance of Long-Term Debt Due Within One Year was $289.2 million at December 31, 2009 with no balance at September 30, 2010, due to the repayment of the remaining balance of Enogex's $400 million 8.125% senior notes which matured on January 15, 2010.

The balance of Accounts Payable was $266.2 million and $297.0 million at September 30, 2010 and December 31, 2009, respectively, a decrease of $30.8 million, or 10.4 percent, primarily due to the timing of outstanding checks clearing the bank and a decrease in volumes and average natural gas prices at OERI.

The balance of Customers' Deposits was $67.0 million and $85.6 million at September 30, 2010 and December 31, 2009, respectively, a decrease of $18.6 million, or 21.7 percent, primarily due to the reclassification of a customer deposit at Enogex to Deferred Revenues as a result of completing the construction of a certain pipeline discussed below.

The balance of Accrued Taxes was $57.2 million and $37.0 million at September 30, 2010 and December 31, 2009, respectively, an increase of $20.2 million or 54.6 percent, primarily due to ad valorem tax accruals and payments.

The balance of Accrued Interest was $30.2 million and $60.6 million at September 30, 2010 and December 31, 2009, respectively, a decrease of $30.4 million, or 50.2 percent, primarily due to the timing of interest payments on long-term debt in 2010 partially offset by additional interest accrued on long-term debt.

The balance of Fuel Clause Over Recoveries was $68.0 million and $187.5 million at September 30, 2010 and December 31, 2009, respectively, a decrease of $119.5 million, or 63.7 percent, primarily due to the fact that the amount billed to retail customers was lower than OG&E's cost of fuel. The fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances.

The balance of Other Current Liabilities was $53.1 million and $32.4 million at September 30, 2010 and December 31, 2009, respectively, an increase of $20.7 million, or 63.9 percent, primarily due to the over recovery of various rate riders, including the Windspeed rider, the OU Spirit rider and the Smart Grid rider, and an increase in legal accruals at OG&E.

The balance of Long-Term Debt was $2,372.8 million and $2,088.9 million at September 30, 2010 and December 31, 2009, respectively, an increase of $283.9 million, or 13.6 percent, primarily due to OG&E's issuance of $250 million of long-term debt in June 2010 and borrowings on Enogex's revolving credit agreement.

The balance of Accrued Benefit Obligations was $331.2 million and $369.3 million at September 30, 2010 and December 31, 2009, respectively, a decrease of $38.1 million, or 10.3 percent, primarily due to pension plan contributions during the second and third quarters of 2010 partially offset by accruals for pension expense.

The balance of Deferred Income Taxes was $1,422.4 million and $1,246.6 million at September 30, 2010 and December 31, 2009, respectively, an increase of $175.8 million, or 14.1 percent, primarily due to accelerated bonus tax depreciation which resulted in higher Federal and state deferred tax accruals as discussed in Note 7 of Notes to Condensed Consolidated Financial Statements.

The balance of Regulatory Liabilities was $185.1 million and $168.2 million at September 30, 2010 and December 31, 2009, respectively, an increase of $16.9 million, or 10.0 percent, primarily due to increases related to the removal obligations and Oklahoma pension regulatory liabilities.

The balance of Deferred Revenues was $37.2 million at September 30, 2010 with no balance at December 31, 2009. In January 2009, Enogex entered into a Facility Construction, Ownership and Operating Agreement for the installation of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Construction of the required facilities was completed during August 2010. Aid in Construction payments of $37.2 million received in excess of construction costs have been recognized as Deferred Revenues on the Company's Condensed Consolidated Balance Sheet and will be amortized on a straight-line basis of $1.2 million per year over the life of the related Intrastate Firm Transportation Services agreement under which service will commence in June 2011.

Off-Balance Sheet Arrangements

Except as discussed below, there have been no significant changes in the Company's off-balance sheet arrangements from those discussed in the Company's 2009 Form 10-K.

OG&E Railcar Lease Agreement

At September 30, 2010, OG&E had a noncancellable operating lease with purchase options, covering 1,462 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. At the end of the lease term, which is January 31, 2011, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $31.5 million.

On February 10, 2009, OG&E executed a short-term lease agreement for 270 railcars in accordance with new coal transportation contracts with BNSF Railway and Union Pacific. These railcars were needed to replace railcars that have been taken out of service or destroyed. The lease agreement expired with respect to 135 railcars on November 2, 2009 and was not replaced. The lease agreement with respect to the remaining 135 railcars expired on March 5, 2010 and is now continuing on a month-to-month basis with a 30-day notice required by either party to terminate the agreement.

OG&E is also required to maintain all of the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

Liquidity and Capital Requirements

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and Enogex. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, hedging activities, delays in recovering unconditional fuel purchase obligations, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings. See “Future Sources of Financing – Short-Term Debt” for information regarding the Company’s revolving credit agreements and commercial paper.

Net Available Liquidity

At September 30, 2010, the Company had $8.5 million of cash and cash equivalents. At September 30, 2010, the Company had $966.5 million of net available liquidity under its revolving credit agreements.

Potential Collateral Requirements

Derivative instruments are utilized in managing the Company's commodity price exposures and in OERI's asset management, marketing and trading activities and hedging activities executed on behalf of the Company. Agreements governing the derivative instruments may require the Company to provide collateral in the form of cash or a letter of credit in the event mark-to-market exposures exceed contractual thresholds or the Company's credit ratings are lowered. Future collateral requirements are uncertain, and are subject to terms of the specific agreements and to fluctuations in natural gas and NGLs market prices.

On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"). While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for derivatives, including mandatory clearing of certain swaps, exchange trading, margin requirements and other transparency requirements. The Dodd-Frank Act contains provisions that should exempt certain derivatives end-users from much of the clearing requirements. It is unclear whether end-users will be exempt from the margin requirements. The scope of the margin requirements and the end user exemption is uncertain and will be further defined through rulemaking proceedings at the Commodity Futures Trading Commission and the Securities and Exchange Commission. Further, although the Company may qualify for certain exemptions, its derivative counterparties may be subject to new capital, margin and business conduct requirements imposed as a result of the new legislation, which may increase the Company's transaction costs or make it more difficult to enter into hedging transactions on favorable terms. The Company's inability to enter into hedging transactions on favorable terms, or at all, could increase operating expenses and put the Company at increased exposure to risks of adverse changes in commodities prices. If, as a result of the rulemaking associated with the Dodd-Frank Act, the Company does not qualify for any exemptions related to clearing requirements and/or are subject to margin requirements, the Company would be subject to higher costs and increased collateral requirements. The impact of the provisions of the Dodd-Frank Act on the Company cannot be determined pending issuance of the final implementing regulations.

Cash Flows

	Nine Months Ended September 30,	
(In millions)	2010	2009
Net cash provided from operating activities	$ 586.9	$ 439.3
Net cash used in investing activities	(586.0)	(655.4)
Net cash (used in) provided from financing activities	(50.5)	44.0

The increase of $147.6 million, or 33.6 percent, in net cash provided from operating activities during the nine months ended September 30, 2010 as compared to the same period in 2009 was primarily due to:

- Ÿ An increase in cash receipts for sales at Enogex and OERI due to an increase in natural gas prices and NGLs prices and volumes during the nine months ended September 30, 2010 as compared to the same period in 2009;
- Ÿ An income tax refund received in February 2010 related to a carry back of the 2008 tax loss resulting from a change in tax method of accounting for capitalization of repair expenditures;
- Ÿ A cash collateral payment to counterparties of OERI related to OERI's NGLs hedge positions during the nine months ended September 30, 2009; and
- Ÿ Cash received during the nine months ended September 30, 2010 from the implementation of rate increases and riders at OG&E.

These increases in net cash provided from operating activities were partially offset by:

- an increase in payments for purchases at Enogex and OERI due to an increase in natural gas prices and NGLs prices and volumes during the nine months ended September 30, 2010 as compared to the same period in 2009; and
- higher fuel refunds at OG&E during the nine months ended September 30, 2010 as compared to the same period in 2009.

The decrease of $69.4 million, or 10.6 percent, in net cash used in investing activities during the nine months ended September 30, 2010 as compared to the same period in 2009 primarily related to higher levels of capital expenditures in 2009 related to OU Spirit and the Windspeed transmission line constructed by OG&E which was placed in service on March 31, 2010 partially offset by higher levels of capital expenditures for pipeline and processing projects at Enogex in 2010.

The decrease of $94.5 million in net cash provided from financing activities during the nine months ended September 30, 2010 as compared to the same period in 2009 was primarily due to:

- Ÿ repayment of the remaining balance of Enogex's $400 million 8.125% senior notes which matured on January 15, 2010 partially offset by the retirement of $110.8 million of senior notes related to the tender offer Enogex completed in July 2009;
- Ÿ proceeds received from the issuance of $200 million of long-term debt at Enogex in June 2009; and
- Ÿ a decrease in the issuance of common stock during the nine months ended September 30, 2010.

These decreases in net cash provided from financing activities were partially offset by:

- Ÿ proceeds received from the issuance of $250 million of long-term debt at OG&E in June 2010;
- Ÿ an increase in short-term debt borrowings during the nine months ended September 30, 2010;
- Ÿ a higher level of proceeds received from borrowings on Enogex's line of credit during the nine months ended September 30, 2010; and
- Ÿ a higher level of repayments made on Enogex's line of credit during the nine months ended September 30, 2009.

Future Capital Requirements and Financing Activities

Capital Expenditures

The Company's consolidated estimates of capital expenditures are: 2010 - $865 million, 2011 - $1,185 million, 2012 - $760 million, 2013 - $695 million, 2014 - $530 million and 2015 - $390 million. These capital expenditures represent the base maintenance capital expenditures (i.e., capital expenditures to maintain and operate the Company's businesses) plus capital expenditures for known and committed projects (collectively referred to as the "Base Capital Expenditure Plan"). Capital expenditures estimated for the next five years and beyond are as follows:

(In millions)	Less than 1 year (2010)	1-3 years (2011-2012)	3-5 years (2013-2014)	More than 5 years	Total
OG&E Base Transmission	$ 40	$ 65	$ 50	$ 25	$ 180
OG&E Base Distribution	220	435	420	210	1,285
OG&E Base Generation	50	115	100	50	315
OG&E Other	30	50	50	25	155
Total OG&E Base Transmission, Distribution, Generation and Other	340	665	620	310	1,935
OG&E Known and Committed Projects:					
Transmission Projects:					
Sunnyside-Hugo (345 kV)	25	160	---	---	185
Sooner-Rose Hill (345 kV)	10	50	---	---	60
Windspeed (345 kV)	25	---	---	---	25
Balanced Portfolio 3E Projects	---	220	160	---	380
SPP Priority Projects (A)	---	70	245	---	315
Total Transmission Projects	60	500	405	---	965
Other Projects:					
Smart Grid Program (B)	40	120	60	10	230
Crossroads (C)	160	290	---	---	450
System Hardening	10	20	---	---	30
Other	15	20	---	---	35
Total Other Projects	225	450	60	10	745
Total OG&E Known and Committed Projects	285	950	465	10	1,710
Total OG&E (D)	625	1,615	1,085	320	3,645
Enogex (Base Maintenance and Known and Committed Projects) (E)	220	280	90	45	635
OGE Energy	20	50	50	25	145
Total capital expenditures	$ 865	$ 1,945	$ 1,225	$ 390	$ 4,425

(A) On June 30, 2010, the SPP issued notices to construct to OG&E to build two 345 kilovolt transmission lines as discussed in Note 14 of Notes to Condensed Consolidated Financial Statements.

(B) These capital expenditures are net of the Smart Grid $130 million grant approved by the U.S. Department of Energy.

(C) These capital expenditures assume the 227.5 MW configuration.

(D) The Base Capital Expenditure Plan above excludes any environmental expenditures associated with Best Available Retrofit Technology ("BART") requirements due to the uncertainty regarding BART costs. As discussed in "– Environmental Laws and Regulations" below, pursuant to a proposed regional haze agreement OG&E has agreed to install low nitrogen oxide ("NOX") burners and related equipment at the three affected generating stations. Preliminary estimates indicate the cost will be $100 million (plus or minus 30 percent). For further information, see "–

Environmental Laws and Regulations” below.
(E) These capital expenditures represent 100 percent of Enogex capital expenditures, of which a portion may be funded by ArcLight.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets and at Enogex, will be evaluated based upon their impact upon achieving the Company’s financial objectives. The capital expenditure projections related to Enogex in the table above reflect base market conditions at October 28, 2010 and do not reflect the potential opportunity for a set of growth projects that could materialize.

Pension Plan Funding

In the third quarter of 2010, the Company contributed $10 million to its pension plan for a total contribution of $50 million to its pension plan during 2010. No additional contributions are expected in 2010.

Fuel Refund

As a result of an interim fuel filing which began in July 2010, OG&E expects to refund to its customers $100 million of prior fuel over recoveries by December 2010, of which $50 million is expected to be refunded during the fourth quarter of 2010.

Security Ratings

Access to reasonably priced capital is dependent in part on credit and security ratings. On October 6, 2010, Standard and Poor's Ratings Services ("Standard and Poor's") revised the outlook on Enogex from stable to negative. All ratings at OGE Energy and OG&E remained unchanged and with a stable outlook. Standard and Poor's indicated that the revised outlook at Enogex was primarily due to the recently announced transaction with ArcLight. The revised outlook did not trigger any collateral requirements or change fees under the revolving credit agreement.

Future Sources of Financing

Management expects that cash generated from operations, proceeds from the issuance of long and short-term debt and proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings will be adequate over the next three years to meet anticipated cash needs and to fund future growth opportunities. Additionally, if the transaction with ArcLight closes, the Company will have an additional source of funding for growth opportunities at Enogex. 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 and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $224.0 million and $175.0 million at September 30, 2010 and December 31, 2009, respectively, and was comprised entirely of outstanding commercial paper borrowings at OGE Energy. At September 30, 2010, Enogex had $35.0 million in outstanding borrowings under its revolving credit agreement with no outstanding borrowings at December 31, 2009. As Enogex's credit agreement matures on March 31, 2013, borrowings thereunder are classified as long-term debt in the Company's Condensed Consolidated Balance Sheets. The following table provides information regarding the Company's revolving credit agreements and available cash at September 30, 2010.

Revolving Credit Agreements and Available Cash

Entity	Aggregate Commitment	Amount Outstanding	Weighted-Average Interest Rate	Maturity
	(In millions)			
OGE Energy	$ 596.0	$ 224.0	0.37%	December 6, 2012
OG&E	389.0	9.5	0.14%	December 6, 2012
Enogex	250.0	35.0	0.57%	March 31, 2013

	1,235.0	268.5	0.39%	
Cash	8.5	N/A	N/A	N/A
Total	$ 1,243.5	$ 268.5	0.39%	

OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any time for a two-year period beginning January 1, 2009 and ending December 31, 2010. See Note 10 of Notes to the 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 effect on the Company's Condensed Consolidated Financial Statements. However, the Company believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, impairment estimates, contingency reserves, asset retirement obligations, fair value and cash flow hedges, regulatory assets and liabilities, unbilled revenues for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable and the valuation of purchase and sale contracts. The selection, application and disclosure of the Company's critical accounting estimates have been discussed with the Company's Audit Committee and are discussed in detail in Management's Discussion and Analysis of Financial Condition and Results of Operations in the Company's 2009 Form 10-K.

Accounting Pronouncements

See Notes to Condensed Consolidated Financial Statements for a discussion of accounting pronouncements that are applicable to the Company.

Commitments and Contingencies

Except as disclosed otherwise in this Form 10-Q and the Company's 2009 Form 10-K, 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 13 and 14 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q and Notes 13 and 14 of Notes to Consolidated Financial Statements and Item 3 of Part I of the 2009 Form 10-K for a discussion of the Company's commitments and contingencies.

Environmental Laws and Regulations

The activities of OG&E and Enogex are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators, regulating future construction activities to avoid endangered species or enjoining some or all of the operations of facilities deemed in noncompliance with permits issued pursuant to such environmental laws and regulations. These environmental laws and regulations are discussed in detail in Management's Discussion and Analysis of Financial Condition and Results of Operations in the Company's 2009 Form 10-K. Except as set forth below, there have been no material changes to such items.

Air

RICE MACT Amendments

On March 5, 2009, the U.S. Environmental Protection Agency ("EPA") initiated rulemaking concerning new national emission standards for hazardous air pollutants for existing reciprocating internal combustion engines by proposing amendments to the National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engine Maximum Achievable Control Technology ("proposed RICE MACT Amendments"). On March 3, 2010, the EPA published final rules on a portion of its original proposed amendments and established national emission standards for hazardous air pollutants for three types of compression ignition reciprocating internal combustion engines (“2010 CI RICE MACT Amendments”). The 2010 CI RICE MACT Amendments were effective May 3, 2010 and are expected to have an insignificant impact to the Company. The remaining provisions of the proposed RICE MACT Amendments were effective October 19, 2010. The costs that may be incurred to comply with these remaining proposed regulations, including the testing and modification of the spark ignition engines, are uncertain at this time. The current compliance deadline is three years from the effective date of the enacted rules.

Regional Haze

On June 15, 2005, the EPA issued final amendments to its 1999 regional haze rule. These regulations are intended to protect visibility in national parks and wilderness areas (“Class I areas”) throughout the United States. In Oklahoma, the Wichita Mountains are the only area covered under the regulation. However, Oklahoma’s impact on parks in other states must also be evaluated. Sulfates and nitrate aerosols can lead to the degradation of visibility. The state of Oklahoma joined with eight other central states to address these visibility impacts.

OG&E was required to evaluate the installation of BART to address regional haze at sources built between 1962 and 1977. The Oklahoma Department of Environmental Quality ("ODEQ") made a preliminary determination to accept an application for a waiver from BART requirements for the Horseshoe Lake generating station based on modeling showing no significant impact on visibility in nearby Class I areas. The Horseshoe Lake waiver was included in the ODEQ regional haze state implementation plan ("SIP") submitted to the EPA on February 18, 2010.

Waivers could not be obtained for the BART-eligible units at OG&E's Seminole, Muskogee and Sooner generating stations. OG&E submitted a BART compliance plan for Seminole on March 30, 2007 committing to installation of NOX controls on all three units. On May 30, 2008, OG&E filed BART evaluations for the affected generating units at the Muskogee and Sooner generating stations. In this filing, OG&E indicated its intention to install low NOX combustion technology at its affected generating stations and to continue to burn low sulfur coal at the four coal-fired generating units at its Muskogee and Sooner generating stations. OG&E did not propose the installation of scrubbers at these four coal-fired generating units because OG&E concluded that, consistent with the EPA's regulations on BART, the installation of scrubbers (at an estimated cost of more than $1.0 billion) would not be cost-effective. The ODEQ published a draft SIP for public review on November 13, 2009. This draft SIP suggested that scrubbers would be needed to comply with the regional haze regulations, but noted OG&E's cost-effectiveness analysis. Following negotiations with the ODEQ, in February 2010 OG&E and the ODEQ entered into an Agreement ("Agreement") which specifies that BART for reducing NOX emissions at all seven BART-eligible units at the Seminole, Muskogee and Sooner generating stations should be the installation of low NOX burners with overfire air (and flue gas recirculation on two of the affected units) and accompanying emission rate and annual emission tonnage limits. Preliminary estimates based on recent industry experience and cost projections estimate the total cost of the NOX-related equipment at the three affected generating stations at $100 million (plus or minus 30 percent). After OG&E obtains estimates from vendors based on a detailed engineering design, it will have a more firm estimate of the exact cost of the NOX-related equipment subject to changes in the cost of basic materials. Under the Agreement, the specified BART for reducing sulfur dioxide ("SO2") at the four coal-fired units at the Muskogee and Sooner generating stations would be continued use of low sulfur coal and emission rate and annual emission tonnage limits consistent with such use of low sulfur coal. If the EPA approves Oklahoma's regional haze SIP, implementation of these BART requirements would be required within five years of the approval.

Under the Agreement, there also would be an alternative compliance obligation in the event that the EPA disapproves the aforementioned BART determination and the underlying conclusion that dry flue gas desulfurization units with Spray Dryer Absorber ("Dry Scrubbers") are not cost-effective. In such an event, and only after OG&E has exhausted all judicial and administrative appeals of the EPA disapproval, OG&E would have two options. First, OG&E could choose to install Dry Scrubbers (or meet the corresponding SO2 emissions limits associated with Dry Scrubbers) by January 1, 2018. Second, OG&E could choose to comply with the regional haze regulations by implementing a fuel switching alternative. This alternative would require OG&E to achieve a combined annual SO2 emission limit by December 31, 2026 that is equivalent to: (i) the SO2 emission limits associated with installing and operating Dry Scrubbers on two of the BART-eligible coal-fired units and (ii) being at or below the SO2 emissions that would result from switching the other two coal-fired units to natural gas. If OG&E has elected to comply with this alternative and if, prior to January 1, 2022, any of these units is required by any environmental law other than the regional haze rule to install flue gas desulfurization equipment or achieve an SO2 emissions rate lower than 0.10 lbs/Million British thermal unit, and if OG&E proceeds to take all necessary steps to comply with such legal requirement, the enforceable emission limits in the operating permits for the affected coal units would be adjusted to reflect the installation of that equipment or the emission rates specified under such legal requirement and OG&E would no longer be required to undertake the 2026 emission levels.

The ODEQ included the Agreement in its regional haze SIP that it submitted to the EPA on February 18, 2010. It is anticipated that the EPA will take final action on the SIP for regional haze during the first quarter of 2011. The possible EPA actions range from approval of the regional haze SIP to disapproval of the regional haze SIP combined with the issuance of a Federal implementation plan for regional haze in Oklahoma. OG&E cannot predict what action the EPA will take.

Until the EPA takes final action on the regional haze SIP, the total cost of compliance, including capital expenditures, cannot be estimated by OG&E with a reasonable degree of certainty. OG&E expects that any necessary expenditures for the installation of emission control equipment will qualify as part of a pre-approval plan to handle state and federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E's retail customers under House Bill 1910, which was enacted into law in May 2005.

Climate Change

There are state, national and international efforts to address possible effects of global climate change and regulate the emission of greenhouse gases including, most significantly, carbon dioxide. In addition, there is litigation against other companies in which the plaintiffs seek to compel either reductions in the future emission of greenhouse gases or compensation for alleged damages resulting from past emissions of greenhouse gases. Congress has considered legislation that, if enacted, could require reductions of greenhouse gas emissions of as much as 83 percent below the baseline 2005 level, perhaps by implementing a cap-and-trade-system. The Federal legislative proposals also generally included renewable energy standards, energy efficiency mandates and other requirements. It is uncertain at this time whether, and in what form, such legislation will ultimately be adopted. The EPA has begun to implement regulations pertaining to greenhouse gases. The EPA has finalized rules that require reporting of greenhouse gases from certain industry and implementation of "best available control technology" for any new or modified source that would increase greenhouse gases above a certain level. The cost of compliance is unknown at this time. If legislation or regulations are passed at the Federal or state levels in the future requiring mandatory reductions of carbon dioxide and other greenhouse gases for the Company's facilities to address climate change, this could result in significant additional capital expenditures and compliance costs.

Uncertainty surrounding global climate change and environmental concerns related to new coal-fired generation development is changing the mix of the potential sources of new generation in the region. Adoption of renewable portfolio standards would be expected to increase the region's reliance on wind generation. An Oklahoma renewable portfolio standard with a statewide goal of renewable energy capacity (on an installed electric generation capacity basis) of 15 percent by year 2015 became effective in May 2010. A federal renewable portfolio standard has not yet been established.

On April 1, 2010, the EPA and the U.S. Department of Transportation's National Highway Traffic Safety Administration issued a joint rule to establish new greenhouse gas emissions regulations that affect tailpipe standards for model years 2012 – 2016 light-duty vehicles. This rule makes greenhouse gas emissions subject to regulation under the Federal Clean Air Act for stationary sources as well as for mobile sources. As a result, OG&E's facilities may be required to include greenhouse gas emission limits in permits issued pursuant to the Federal Clean Air Act. On June 3, 2010, the EPA published the final rule tailoring the applicability criteria that determine which stationary sources and modification projects become subject to permitting requirements for greenhouse gas ("GHG") emissions under the Prevention of Significant Deterioration ("PSD") and Title V programs of the Federal Clean Air Act ("Tailoring Rule"). The Tailoring Rule establishes a two-step process for implementing regulation of GHGs under the PSD and Title V programs. The Tailoring Rule became effective August 2, 2010. The effects of the Tailoring Rule cannot be determined until the EPA publishes guidance regarding how control requirements will be established.

Sulfur Dioxide

The Federal Clean Air Act includes an acid rain program to reduce SO2 emissions. Reductions were obtained through a program of emission (release) allowances issued by the EPA to power plants covered by the acid rain program. Each allowance permits one ton of SO2 to be released from the chimney. Plants may only release as much SO2 as they have allowances. Allowances may be banked and traded or sold nationwide. Beginning in 2000, OG&E became subject to more stringent SO2 emission requirements in Phase II of the acid rain program. These lower limits had no significant financial impact due to OG&E's earlier decision to burn low sulfur coal. In 2009, OG&E's SO2 emissions were below the allowable limits.

On June 2, 2010, the EPA released its final rule strengthening the primary, health-based, national ambient air quality standards ("NAAQS") for SO2. The Final Rule revokes the existing 24-hour and annual standards and establishes a new one-hour standard at a level of 75 parts per billion. The EPA intends to complete attainment designations within two years of promulgation of the revised SO2 standard, which is expected by June 2012. States with areas designated nonattainment in 2012 would need to submit a SIP to the EPA by early 2014 outlining actions that will be taken to meet the standards as expeditiously as possible, but no later than August 2017. The Company will continue to monitor the EPA's attainment designation activities.

Transport Rule

On July 6, 2010 the EPA proposed a rule ("Transport Rule") that would require 31 states and the District of Columbia to reduce power plant emissions that contribute to ozone and fine particle pollution in other states. Of the 31 states, 28 states would be required to reduce both annual SO2 and NOX emissions and 26 states, including Oklahoma, would be required to reduce NOX emissions during only the ozone season (May-September) because they contribute to downwind states' ozone pollution. The Company is reviewing the proposed rule and any potential impact it may have.

Coal Ash

As previously reported in the Company's 2009 Form 10-K, the EPA had announced that it was considering regulation of coal ash. On June 21, 2010 the EPA published its proposed rules for regulation of coal ash. The proposal includes two options for the disposal of coal ash, one option that treats it as hazardous waste and another option that treats it as non-hazardous waste. The Company is currently reviewing the proposed rules and any potential impact they may have to its operations and may submit written comments to the EPA.

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 2009 Form 10-K 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 of OERI are conducted throughout the year subject to daily and monthly trading stop loss limits set by the Risk Oversight Committee. Those trading stop loss limits currently are $2.5 million. The daily loss exposure from trading activities is measured primarily using value-at-risk ("VaR"), which estimates the potential losses the trading activities could incur over a specified time horizon and confidence level. Currently, the Company utilizes the variance/co-variance method for calculating VaR. The VaR limit set by the Risk Oversight Committee for the Company's trading activities, assuming a 95 percent confidence level, currently is $1.5 million. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company's operating income.

A sensitivity analysis has been prepared to estimate the Company's exposure to market risk created by trading activities. The value of trading positions is a summation of the fair values calculated for each net commodity position based upon quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in quoted market prices. The result of this analysis, which may differ from actual results, is as follows at:

September 30 (In millions)	2010	2009
Commodity market risk, net	$ 0.1	$ 0.2

Non-Trading Activities

The prices of natural gas and NGLs and NGLs 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 the Company receives for operating some of its assets. To partially reduce non-trading commodity price risk, the Company utilizes risk mitigation tools such as default processing fees and ethane rejection capabilities to protect its downside exposure while maintaining its upside potential. Additionally, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the Company's operating income. 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.

Normal purchases and normal sales contracts are not recorded in Price Risk Management Assets or Liabilities in the Condensed Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by its operations, (ii) commodity contracts for the sale of NGLs produced by Enogex's gathering and processing business, (iii) electric power contracts by OG&E and (iv) fuel procurement by OG&E.

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 forward price curves. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 20 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 at:

September 30 (In millions)	2010	2009
Commodity market risk, net	$ 17.2	$ 7.6

The increase in downside commodity market risk reflected in the table above is primarily due to favorable commodity price conditions at September 30, 2010 as compared to September 30, 2009. These favorable conditions increased the Company's per unit exposure. During 2009, the Company reduced its volumetric exposure to commodity market risk by converting a portion of its agreements from commodity market based compensation to fixed-fee based compensation. Absent these conversions, the commodity market risk at September 30, 2010 would have been even greater.

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 ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer ("CEO") and chief financial officer ("CFO"), allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the CEO and CFO, of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the CEO and CFO have concluded that the Company's disclosure controls and procedures are effective.

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

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

Reference is made to Part I, Item 3 of the Company's 2009 Form 10-K for a description of certain legal proceedings presently pending. Except as set forth below and in Notes 13 and 14 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. Hull v. Enogex LLC. On November 14, 2008, a natural gas gathering pipeline owned by Enogex ruptured in Grady County, near Alex, Oklahoma, resulting in a fire that caused injuries to one resident and destroyed three residential structures. After the incident, Enogex coordinated and assisted the affected residents. Enogex resolved matters with two of the residents and Enogex continued to seek resolution with a remaining resident. This resident

filed a legal action in May 2009 in the District Court of Cleveland County, Oklahoma, against OGE Energy and Enogex. This matter was resolved by the parties on April 8, 2010. The ultimate resolution of this incident was not material to the Company in light of previously established reserves and insurance coverage.

2. Oxley Litigation. OG&E has been sued by John C. Oxley D/B/A Oxley Petroleum et al. in the District Court of Haskell County, Oklahoma. This case has been pending for more than 11 years. The plaintiffs alleged that OG&E breached the terms of contracts covering several wells by failing to purchase gas from the plaintiffs in amounts set forth in the contracts. The plaintiffs' most recent Statement of Claim describes $2.7 million in take-or-pay damages (including interest) and $36 million in contract repudiation damages (including interest), subject to the limitation described below. In 2001, OG&E agreed to provide the plaintiffs with $5.8 million of consideration and the parties agreed to arbitrate the dispute. The arbitration hearing was completed and the final briefs were provided to the arbitration panel on March 17, 2010. On

May 19, 2010, the panel issued an arbitration award in an amount less than the consideration previously paid by OG&E and, as a result, OG&E did not owe any additional amount. The Company now considers this case closed.

3. Franchise Fee Lawsuit. On June 19, 2006, two OG&E customers brought a putative class action, on behalf of all similarly situated customers, in the District Court of Creek County, Oklahoma, challenging certain charges on OG&E's electric bills. The plaintiffs claim that OG&E improperly charged sales tax based on franchise fee charges paid by its customers. The plaintiffs also challenge certain franchise fee charges, contending that such fees are more than is allowed under Oklahoma law. OG&E's motion for summary judgment was denied by the trial judge. In January 2007, the Oklahoma Supreme Court "arrested" the District Court action until, and if, the propriety of the complaint of billing practices is determined by the OCC. In September 2008, the plaintiffs filed an application with the OCC asking the OCC to modify its order which authorizes OG&E to collect the challenged franchise fee charges. On December 9, 2009 the OCC issued an order dismissing the plaintiffs' request for a modification of the 1994 OCC order which authorized OG&E to collect and remit sales tax on franchise fee charges. In its December 9, 2009 order, the OCC advised the plaintiffs that the ruling does not address the question of whether OG&E's collection and remittance of such sales tax should be discontinued prospectively. On April 19, 2010, the OCC issued a final order dismissing with prejudice the applicants' claims for recovery of previously paid taxes on franchise fees and approving the closing of this matter. On June 10, 2010, the plaintiffs filed a motion in the District Court of Creek County, Oklahoma, asking the court to proceed with the original class action. On July 8, 2010, a hearing in this matter was held and the court granted the plaintiffs motion to lift the stay of discovery previously imposed by the Oklahoma Supreme Court but denied any other specific relief pending further action by the court. On August 4, 2010, OG&E filed an application to assume original jurisdiction and a petition for a writ of prohibition with the Oklahoma Supreme Court. On September 13, 2010, the Oklahoma Supreme Court issued a writ prohibiting the District Court judge from proceeding further in this case except to dismiss the case. On September 20, 2010, the plaintiffs filed a motion to reconsider this matter with the Oklahoma Supreme Court. While OG&E cannot predict the precise outcome of this lawsuit, based on the information known at this time, OG&E believes that this lawsuit will not have a material adverse effect on the Company's consolidated financial position or results of operations.

4. Will Price, et al. v. El Paso Natural Gas Co., et al. (Price I). On September 24, 1999, various subsidiaries of the Company were served with a class action petition filed in the District Court of Stevens County, Kansas by Quinque Operating Company and other named plaintiffs alleging the mismeasurement of natural gas on non-Federal lands. On April 10, 2003, the court entered an order denying class certification. On May 12, 2003, the plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended class action petition, and the court granted the motion on July 28, 2003. In its amended petition (the "Fourth Amended Petition"), OG&E and Enogex Inc. were omitted from the case but two of the Company's other subsidiary entities remained as defendants. The plaintiffs' Fourth Amended Petition seeks class certification and alleges that 60 defendants, including two of the Company's subsidiary entities, have improperly measured the volume of natural gas. The Fourth Amended Petition asserts theories of civil conspiracy, aiding and abetting, accounting and unjust enrichment. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

Discovery was conducted on the class certification issues, and the parties fully briefed these same issues. A hearing on class certification issues was held April 1, 2005. In May 2006, the court heard oral argument on a motion to intervene filed by Colorado Consumers Legal Foundation, which is claiming entitlement to participate in the putative class action. The court has not yet ruled on the motion to intervene.

The class certification issues were briefed and argued by the parties in 2005 and proposed findings of facts and conclusions of law on class certification were filed in 2007. On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On February 10, 2010 the court heard arguments on the rehearing request and by an order dated March 31, 2010, the court denied the plaintiffs' request for rehearing.

The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

5. Will Price, et al. v. El Paso Natural Gas Co., et al. (Price II). On May 12, 2003, the plaintiffs (same as those in the Fourth Amended Petition in Price I above) filed a new class action petition in the District Court of Stevens County, Kansas naming the same defendants and asserting substantially identical legal and/or equitable theories as in the Fourth Amended Petition of the Price I case. OG&E and Enogex Inc. were not named in this case, but two subsidiary entities of the Company were named in this case. The plaintiffs allege that the defendants mismeasured the Btu content of natural

gas obtained from or measured for the plaintiffs. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

Discovery was conducted on the class certification issues, and the parties fully briefed these same issues. A hearing on class certification issues was held April 1, 2005. In May 2006, the court heard oral argument on a motion to intervene filed by Colorado Consumers Legal Foundation, which is claiming entitlement to participate in the putative class action. The court has not yet ruled on the motion to intervene.

The class certification issues were briefed and argued by the parties in 2005 and proposed findings of facts and conclusions of law on class certification were filed in 2007. On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On February 10, 2010 the court heard arguments on the rehearing request and by an order dated March 31, 2010, the court denied the plaintiffs' request for rehearing.

The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Item 1A. Risk Factors.

There have been no significant changes in the Company's risk factors from those discussed in the Company's 2009 Form 10-K, which are incorporated herein by reference.

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 qualified defined contribution retirement plan and reflect shares purchased with employee contributions as well as the portion attributable to the Company's matching contributions.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
7/1/10 – 7/31/10	57,300	$ 37.29	N/A	N/A
8/1/10 – 8/31/10	25,200	$ 39.92	N/A	N/A
9/1/10 – 9/30/10	12,900	$ 40.40	N/A	N/A

N/A – not applicable

Item 6. Exhibits.

Exhibit No.	Description
2.01	Investment Agreement dated as of October 5, 2010 by and between OGE Energy Corp., Enogex Holdings LLC and Bronco Midstream Holdings, LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed October 6, 2010 (File No. 1-12579) and incorporated by reference herein)
10.01	Credit Agreement dated as of April 1, 2008, by and among Enogex LLC, the Lenders thereto, Wachovia Bank, National Association, as Administrative Agent, The Royal Bank of Scotland plc, as Syndication Agent, and JPMorgan Chase Bank, N.A, Mizuho Corporate Bank, LTD. and Union Bank of California, as Co-Documentation Agents.
10.02	Credit agreement dated December 6, 2006, by and between the Company, the Lenders thereto, Wachovia Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, and The Royal Bank of Scotland plc, UBS Securities LLC and Union Bank of California, N.A., as Co-Documentation Agents.
10.03	Credit agreement dated December 6, 2006, by and between OG&E, the Lenders thereto, Wachovia Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, and The Royal Bank of Scotland plc, Mizuho Corporate Bank and Union Bank of California, N.A., as Co-Documentation Agents.
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.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.PRE	XBRL Taxonomy Presentation Linkbase Document.
101.LAB	XBRL Taxonomy Label Linkbase Document.
101.CAL	XBRL Taxonomy Calculation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.

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 and Chief Accounting Officer

October 29, 2010