OGE ENERGY CORP.
Form 10-Q
October 30, 2009

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, 2009

OR

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

Commission File Number: 1-12579

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant 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 (Sec.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). o 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 x | 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 x

At September 30, 2009, there were 96,791,187 shares of common stock, par value $0.01 per share, outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2009

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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. In addition 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, 2008 ("2008 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, actions of rating agencies and their impact on capital expenditures;
- OGE Energy Corp.'s (collectively, with its subsidiaries, the "Company") ability and the ability of its subsidiaries to 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; 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 2008 Form 10-K.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (In millions, except per share data) | 2009 | 2008 | 2009 | 2008 |
| OPERATING REVENUES | | | | |
| Electric Utility operating revenues | $577.9 | $682.5 | $1,339.9 | $1,589.6 |
| Natural Gas Pipeline operating revenues | 267.4 | 571.8 | 756.1 | 1,795.1 |
| Total operating revenues | 845.3 | 1,254.3 | 2,096.0 | 3,384.7 |
| COST OF GOODS SOLD (exclusive of depreciation and amortization shown below) | | | | |
| Electric Utility cost of goods sold | 223.8 | 368.9 | 559.3 | 892.4 |
| Natural Gas Pipeline cost of goods sold | 190.3 | 467.9 | 532.2 | 1,515.3 |
| Total cost of goods sold | 414.1 | 836.8 | 1,091.5 | 2,407.7 |
| Gross margin on revenues | 431.2 | 417.5 | 1,004.5 | 977.0 |
| Other operation and maintenance | 113.0 | 113.6 | 335.1 | 357.8 |
| Depreciation and amortization | 66.6 | 53.4 | 193.8 | 156.5 |
| Impairment of assets | 0.6 | --- | 2.0 | --- |
| Taxes other than income | 21.3 | 19.3 | 65.5 | 60.7 |
| OPERATING INCOME | 229.7 | 231.2 | 408.1 | 402.0 |
| OTHER INCOME (EXPENSE) | | | | |
| Interest income | 0.3 | 2.3 | 1.4 | 4.4 |
| Allowance for equity funds used during construction | 5.5 | --- | 10.7 | --- |
| Other income | 7.0 | 0.2 | 20.0 | 8.6 |
| Other expense | (3.9) | (3.6) | (8.9) | (18.6) |
| Net other income (expense) | 8.9 | (1.1) | 23.2 | (5.6) |
| INTEREST EXPENSE | | | | |
| Interest on long-term debt | 37.3 | 25.7 | 100.6 | 73.4 |
| Allowance for borrowed funds used during construction | (2.9) | (0.8) | (5.9) | (2.4) |
| Interest on short-term debt and other interest charges | 2.3 | 3.5 | 6.4 | 14.0 |
| Interest expense | 36.7 | 28.4 | 101.1 | 85.0 |
| INCOME BEFORE TAXES | 201.9 | 201.7 | 330.2 | 311.4 |
| INCOME TAX EXPENSE | 64.4 | 60.3 | 104.2 | 96.6 |
| NET INCOME | 137.5 | 141.4 | 226.0 | 214.8 |
| Less: Net income attributable to noncontrolling interest | 0.7 | 1.9 | 1.9 | 5.2 |
| NET INCOME ATTRIBUTABLE TO OGE ENERGY | $136.8 | $139.5 | $224.1 | $209.6 |
| | | | | |
| BASIC AVERAGE COMMON SHARES OUTSTANDING | 96.7 | 92.6 | 96.0 | 92.2 |
| DILUTED AVERAGE COMMON SHARES OUTSTANDING | 97.7 | 93.0 | 96.9 | 92.7 |
| BASIC EARNINGS PER AVERAGE COMMON SHARE | | | | |

| | | | | |
|---|---|---|---|---|
| ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS | $1.42 | $1.51 | $2.34 | $2.27 |
| DILUTED EARNINGS PER AVERAGE COMMON SHARE | | | | |
| ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS | $1.40 | $1.50 | $2.31 | $2.26 |
| DIVIDENDS DECLARED PER SHARE | $0.3550 | $0.3475 | $1.0650 | $1.0425 |

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

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS

| (In millions) | September 30, 2009 (Unaudited) | December 31, 2008 |
|---|---|---|
| ASSETS | | |
| CURRENT ASSETS | | |
| Cash and cash equivalents | $ 2.3 | $ 174.4 |
| Accounts receivable, less reserve of $2.8 and $3.2, respectively | 285.3 | 288.1 |
| Accrued unbilled revenues | 59.5 | 47.0 |
| Income taxes receivable | 40.5 | --- |
| Fuel inventories | 108.1 | 88.7 |
| Materials and supplies, at average cost | 78.8 | 72.1 |
| Price risk management | 9.3 | 11.9 |
| Gas imbalances | 8.0 | 6.2 |
| Accumulated deferred tax assets | 13.0 | 14.9 |
| Fuel clause under recoveries | 0.3 | 24.0 |
| Prepayments | 3.5 | 9.0 |
| Other | 7.0 | 8.3 |
| Total current assets | 615.6 | 744.6 |
| OTHER PROPERTY AND INVESTMENTS, at cost | 42.1 | 42.2 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| In service | 8,221.9 | 7,722.4 |
| Construction work in progress | 553.2 | 399.0 |
| Total property, plant and equipment | 8,775.1 | 8,121.4 |
| Less accumulated depreciation | 3,001.7 | 2,871.6 |
| Net property, plant and equipment | 5,773.4 | 5,249.8 |
| DEFERRED CHARGES AND OTHER ASSETS | | |
| Income taxes recoverable from customers, net | 20.7 | 14.6 |
| Benefit obligations regulatory asset | 324.4 | 344.7 |
| Price risk management | 18.0 | 22.0 |
| McClain Plant deferred expenses | 1.6 | 6.2 |
| Unamortized loss on reacquired debt | 16.8 | 17.7 |
| Unamortized debt issuance costs | 13.9 | 13.5 |
| Other | 71.3 | 63.2 |
| Total deferred charges and other assets | 466.7 | 481.9 |
| TOTAL ASSETS | $ 6,897.8 | $ 6,518.5 |

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, 2009 (Unaudited) | December 31, 2008 |
|---|---|---|
| LIABILITIES AND STOCKHOLDERS' EQUITY | | |
| CURRENT LIABILITIES | | |
| Short-term debt | $ 308.0 | $298.0 |
| Accounts payable | 174.7 | 279.7 |
| Dividends payable | 34.4 | 33.2 |
| Customer deposits | 62.1 | 58.8 |
| Accrued taxes | 60.6 | 26.8 |
| Accrued interest | 30.8 | 48.7 |
| Accrued compensation | 44.2 | 45.2 |
| Long-term debt due within one year | 289.4 | --- |
| Price risk management | 12.7 | 2.3 |
| Gas imbalances | 9.7 | 24.9 |
| Fuel clause over recoveries | 176.4 | 8.6 |
| Other | 43.4 | 62.2 |
| Total current liabilities | 1,246.4 | 888.4 |
| LONG-TERM DEBT | 1,930.8 | 2,161.8 |
| DEFERRED CREDITS AND OTHER LIABILITIES | | |
| Accrued benefit obligations | 318.1 | 350.5 |
| Accumulated deferred income taxes | 1,096.1 | 996.9 |
| Accumulated deferred investment tax credits | 14.2 | 17.3 |
| Accrued removal obligations, net | 164.4 | 150.9 |
| Price risk management | 1.6 | 3.8 |
| Other | 54.9 | 34.9 |
| Total deferred credits and other liabilities | 1,649.3 | 1,554.3 |
| Total liabilities | 4,826.5 | 4,604.5 |
| COMMITMENTS AND CONTINGENCIES (NOTE 12) | | |
| STOCKHOLDERS' EQUITY | | |
| Common stockholders' equity | 880.7 | 802.9 |
| Retained earnings | 1,228.7 | 1,107.6 |
| Accumulated other comprehensive loss, net of tax | (57.2) | (13.7) |
| Total OGE Energy stockholders' equity | 2,052.2 | 1,896.8 |
| Noncontrolling interest | 19.1 | 17.2 |
| Total stockholders' equity | 2,071.3 | 1,914.0 |

| | | |
|---|---|---|
| TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY | $ 6,897.8 | $6,518.5 |

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)

| | OGE Energy Corp. Stockholders' | | | | | |
|---|---|---|---|---|---|---|
| (In millions) | Common Stock | Premium on Capital Stock | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interest | Total |
| Balance at December 31, 2008 | $ 0.9 | $ 802.0 | $ 1,107.6 | $ (13.7) | $ 17.2 | $ 1,914.0 |
| Comprehensive income (loss) | | | | | | |
| Net income for first quarter of 2009 | --- | --- | 16.8 | --- | 0.8 | 17.6 |
| Other comprehensive income (loss), net of tax | | | | | | |
| Defined benefit pension plan and restoration of retirement income plan: | | | | | | |
| Net loss, net of tax ($1.3 pre-tax) | --- | --- | --- | 0.8 | --- | 0.8 |
| Defined benefit postretirement plans: | | | | | | |
| Net loss, net of tax ($0.2 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Deferred hedging losses (($46.2) pre-tax) | --- | --- | --- | (28.3) | --- | (28.3) |
| Amortization of cash flow hedge ($0.2 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Other comprehensive loss | --- | --- | --- | (27.3) | --- | (27.3) |
| Comprehensive income (loss) | --- | --- | 16.8 | (27.3) | 0.8 | (9.7) |
| Dividends declared on common stock | --- | --- | (34.2) | --- | --- | (34.2) |
| Issuance of common stock | 0.1 | 55.7 | --- | --- | --- | 55.8 |
| Balance at March 31, 2009 | $ 1.0 | $ 857.7 | $ 1,090.2 | $ (41.0) | $ 18.0 | $ 1,925.9 |
| Comprehensive income | | | | | | |
| Net income for second quarter of 2009 | --- | --- | 70.5 | --- | 0.4 | 70.9 |
| Other comprehensive income (loss), net of tax | | | | | | |
| Defined benefit pension plan and restoration of retirement income plan: | | | | | | |
| Net loss, net of tax ($1.3 pre-tax) | --- | --- | --- | 0.7 | --- | 0.7 |
| Prior service cost, net of tax ($0.1 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Defined benefit postretirement plans: | | | | | | |
| Prior service cost, net of tax ($0.1 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Deferred hedging losses (($32.4) pre-tax) | --- | --- | --- | (19.8) | --- | (19.8) |
| Amortization of cash flow hedge ($0.1 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Other comprehensive loss | --- | --- | --- | (18.8) | --- | (18.8) |
| Comprehensive income (loss) | --- | --- | 70.5 | (18.8) | 0.4 | 52.1 |
| Dividends declared on common stock | --- | --- | (34.4) | --- | --- | (34.4) |
| Issuance of common stock | --- | 14.1 | --- | --- | --- | 14.1 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Balance at June 30, 2009 | $ 1.0 | $ 871.8 | $ 1,126.3 | $ (59.8) | $ 18.4 | $ 1,957.7 |
| Comprehensive income | | | | | | |
| Net income for third quarter of 2009 | --- | --- | 136.8 | --- | 0.7 | 137.5 |
| Other comprehensive income (loss), net of tax | | | | | | |
| Defined benefit pension plan and restoration of retirement income plan: | | | | | | |
| Net loss, net of tax ($1.3 pre-tax) | --- | --- | --- | 0.8 | --- | 0.8 |
| Defined benefit postretirement plans: | | | | | | |
| Net loss, net of tax ($0.3 pre-tax) | --- | --- | --- | 0.2 | --- | 0.2 |
| Net transition obligation, net of tax ($0.1 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Deferred hedging gains ($2.5 pre-tax) | --- | --- | --- | 1.5 | --- | 1.5 |
| Other comprehensive income | --- | --- | --- | 2.6 | --- | 2.6 |
| Comprehensive income | --- | --- | 136.8 | 2.6 | 0.7 | 140.1 |
| Dividends declared on common stock | --- | --- | (34.4) | --- | --- | (34.4) |
| Issuance of common stock | --- | 7.9 | --- | --- | --- | 7.9 |
| Balance at September 30, 2009 | $ 1.0 | $ 879.7 | $ 1,228.7 | $ (57.2) | $ 19.1 | $ 2,071.3 |

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

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

| | OGE Energy Corp. Stockholders' | | | | | |
|---|---|---|---|---|---|---|
| (In millions) | Common Stock | Premium on Capital Stock | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interest | Total |
| Balance at December 31, 2007 | $ 0.9 | $ 755.3 | $ 1,005.7 | $ (81.0) | $ 10.7 | $ 1,691.6 |
| Comprehensive income | | | | | | |
| Net income for first quarter of 2008 | --- | --- | 13.0 | --- | 1.6 | 14.6 |
| Other comprehensive income, net of tax | | | | | | |
| Defined benefit pension plan and restoration of retirement income plan: | | | | | | |
| Net loss, net of tax ($0.5 pre-tax) | --- | --- | --- | 0.3 | --- | 0.3 |
| Prior service cost, net of tax ($0.1 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Defined benefit postretirement plans: | | | | | | |
| Net loss, net of tax ($0.1 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Prior service cost, net of tax ($0.1 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Deferred hedging gains ($26.0 pre-tax) | --- | --- | --- | 16.0 | --- | 16.0 |
| Amortization of cash flow hedge ($0.1 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Other comprehensive income | --- | --- | --- | 16.7 | --- | 16.7 |
| Comprehensive income | --- | --- | 13.0 | 16.7 | 1.6 | 31.3 |
| Dividends declared on common stock | --- | --- | (32.0) | --- | --- | (32.0) |
| Contributions from partner | --- | --- | --- | --- | 0.5 | 0.5 |
| Issuance of common stock | --- | 2.2 | --- | --- | --- | 2.2 |
| Balance at March 31, 2008 | $ 0.9 | $ 757.5 | $ 986.7 | $ (64.3) | $ 12.8 | $ 1,693.6 |
| | | | | | | |
| Comprehensive income | | | | | | |
| Net income for second quarter of 2008 | --- | --- | 57.1 | --- | 1.7 | 58.8 |
| Other comprehensive income (loss), net of tax | | | | | | |
| Defined benefit pension plan and restoration of retirement income plan: | | | | | | |
| Net loss, net of tax ($0.6 pre-tax) | --- | --- | --- | 0.4 | --- | 0.4 |
| Prior service cost, net of tax ($0.1 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Defined benefit postretirement plans: | | | | | | |
| Net loss, net of tax ($0.2 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Net transition obligation, net of tax ($0.1 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Deferred hedging losses (($22.1) pre-tax) | --- | --- | --- | (13.8) | --- | (13.8) |
| Other comprehensive loss | --- | --- | --- | (13.1) | --- | (13.1) |
| Comprehensive income (loss) | --- | --- | 57.1 | (13.1) | 1.7 | 45.7 |
| Dividends declared on common stock | --- | --- | (32.1) | --- | --- | (32.1) |

| | | | | | | |
|---|---|---|---|---|---|---|
| Issuance of common stock | --- | 10.4 | --- | --- | --- | 10.4 |
| Balance at June 30, 2008 | $ 0.9 | $ 767.9 | $ 1,011.7 | $ (77.4) | $ 14.5 | $ 1,717.6 |
| | | | | | | |
| Comprehensive income | | | | | | |
| Net income for third quarter of 2008 | --- | --- | 139.5 | --- | 1.9 | 141.4 |
| Other comprehensive income, net of tax | | | | | | |
| Defined benefit pension plan and restoration of retirement income plan: | | | | | | |
| Net loss, net of tax ($0.5 pre-tax) | --- | --- | --- | 0.3 | --- | 0.3 |
| Defined benefit postretirement plans: | | | | | | |
| Net loss, net of tax ($0.2 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Deferred hedging gains ($23.8 pre-tax) | --- | --- | --- | 14.6 | --- | 14.6 |
| Amortization of cash flow hedge ($0.1 pre-tax) | --- | --- | --- | 0.1 | --- | 0.1 |
| Other comprehensive income | --- | --- | --- | 15.1 | --- | 15.1 |
| Comprehensive income | --- | --- | 139.5 | 15.1 | 1.9 | 156.5 |
| Dividends declared on common stock | --- | --- | (32.2) | --- | --- | (32.2) |
| Issuance of common stock | --- | 13.5 | --- | --- | --- | 13.5 |
| Balance at September 30, 2008 | $ 0.9 | $ 781.4 | $ 1,119.0 | $ (62.3) | $ 16.4 | $ 1,855.4 |

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

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

| (In millions) | Nine Months Ended September 30, 2009 | 2008 |
|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES | | |
| Net income | $ 226.0 | $ 214.8 |
| Adjustments to reconcile net income to net cash provided from operating activities | | |
| Depreciation and amortization | 193.8 | 156.5 |
| Impairment of assets | 2.0 | --- |
| Deferred income taxes and investment tax credits, net | 132.3 | 134.1 |
| Allowance for equity funds used during construction | (10.7) | --- |
| Loss on disposition of assets | 1.2 | 0.3 |
| Write-down of regulatory assets | --- | 9.2 |
| Stock-based compensation expense | 4.2 | 3.4 |
| Excess tax benefit on stock-based compensation | (3.3) | (1.9) |
| Stock-based compensation converted to cash for tax withholding | (1.7) | --- |
| Price risk management assets | 6.6 | --- |
| Price risk management liabilities | (67.7) | 23.2 |
| Other assets | 11.4 | (14.9) |
| Other liabilities | (34.4) | (21.1) |
| Change in certain current assets and liabilities | | |
| Accounts receivable, net | 2.8 | (40.6) |
| Accrued unbilled revenues | (12.5) | (3.4) |
| Income taxes receivable | (40.5) | --- |
| Fuel, materials and supplies inventories | (26.1) | (24.0) |
| Gas imbalance assets | (1.8) | 4.2 |
| Fuel clause under recoveries | 23.7 | (82.6) |
| Other current assets | 6.8 | 1.5 |
| Accounts payable | (105.0) | (167.2) |
| Customer deposits | 3.3 | 1.5 |
| Accrued taxes | 34.2 | (6.8) |
| Accrued interest | (17.9) | (11.3) |
| Accrued compensation | (1.0) | (15.8) |
| Gas imbalance liabilities | (15.2) | 4.7 |
| Fuel clause over recoveries | 167.8 | (3.8) |
| Other current liabilities | (18.8) | 18.2 |
| Net Cash Provided from Operating Activities | 459.5 | 178.2 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | |
| Capital expenditures (less allowance for equity funds used during construction) | (676.4) | (914.7) |
| Proceeds from sale of assets | 0.8 | 0.2 |

| | | |
|---|---|---|
| Other investing activities | --- | (0.1) |
| Net Cash Used in Investing Activities | (675.6) | (914.6) |
| | | |
| CASH FLOWS FROM FINANCING ACTIVITIES | | |
| Proceeds from long-term debt | 198.4 | 444.7 |
| Proceeds from line of credit | 80.0 | 145.0 |
| Issuance of common stock | 74.9 | 18.5 |
| Increase in short-term debt, net | 10.0 | 444.0 |
| Excess tax benefit on stock-based compensation | 3.3 | 1.9 |
| Contributions from noncontrolling interest partner | --- | 0.5 |
| Dividends paid on common stock | (101.8) | (96.0) |
| Repayment of line of credit | (110.0) | (25.0) |
| Retirement of long-term debt | (110.8) | (1.1) |
| Net Cash Provided from Financing Activities | 44.0 | 932.5 |
| | | |
| NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS | (172.1) | 196.1 |
| CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD | 174.4 | 8.8 |
| CASH AND CASH EQUIVALENTS AT END OF PERIOD | $ 2.3 | $ 204.9 |

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. The vast majority of Enogex’s natural gas gathering, processing, transportation and storage assets are strategically located primarily 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.

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 (“Tallgrass”) to construct high-capacity transmission line projects in western Oklahoma. The Company owns 50 percent of Tallgrass. Tallgrass is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction.

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, based primarily upon head-count, occupancy, usage or the “Distrigas” method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. The Company adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. The Company believes this method provides a reasonable basis for allocating common expenses.

Basis of Presentation

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

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at September 30, 2009 and December 31, 2008, the results of its operations for the three and nine months ended September 30, 2009 and 2008, and the results of its cash flows for the nine months ended September 30, 2009 and 2008, have been included and are of a normal recurring nature except as otherwise disclosed. Management also has evaluated the impact of subsequent events for inclusion in the Company's Condensed Consolidated Financial Statements occurring after September 30, 2009 through October 29, 2009, the date the Company's financial statements were issued, and, in the opinion of management, the Company's Condensed Consolidated Financial Statements and Notes contain all necessary adjustments and disclosures resulting from that evaluation.

Due to seasonal fluctuations and other factors, the operating results for the three and nine months ended September 30, 2009 are not necessarily indicative of the results that may be expected for the year ending December 31, 2009 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, 2008 ("2008 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, 2009 | December 31, 2008 |
|---|---|---|
| Regulatory Assets | | |
| Benefit obligations regulatory asset | $ 324.4 | $344.7 |
| Deferred storm expenses | 28.8 | 32.2 |
| Income taxes recoverable from customers, net | 20.7 | 14.6 |
| Deferred pension plan expenses | 19.2 | 14.6 |
| Unamortized loss on reacquired debt | 16.8 | 17.7 |
| Red Rock deferred expenses | 7.8 | 7.4 |
| McClain Plant deferred expenses | 1.6 | 6.2 |
| Fuel clause under recoveries | 0.3 | 24.0 |
| Miscellaneous | 3.1 | 2.9 |
| Total Regulatory Assets | $ 422.7 | $464.3 |
| | | |
| Regulatory Liabilities | | |
| Fuel clause over recoveries | $ 176.4 | $8.6 |
| Accrued removal obligations, net | 164.4 | 150.9 |
| Miscellaneous | 11.7 | 4.9 |
| Total Regulatory Liabilities | $ 352.5 | $164.4 |

In accordance with the APSC order received by OG&E in May 2009 in its Arkansas rate case, OG&E was allowed recovery of its 2006 and 2007 pension settlement costs. During the second quarter of 2009, OG&E reduced its pension expense and recorded a regulatory asset for approximately $3.2 million, which is reflected in Deferred Pension Plan Expenses in the table above.

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

Price Risk Management Assets and Liabilities

Fair value amounts recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Condensed Consolidated Balance Sheets. The Company has presented the fair values of its contracts under master netting agreements using a net fair value presentation. If these transactions with the same counterparty were presented on a gross basis in the Condensed Consolidated Balance Sheets, current Price Risk Management ("PRM") assets and liabilities would be approximately $29.7 million and $33.1 million, respectively, at September 30, 2009, and non-current PRM assets and liabilities would be approximately $39.5 million and $23.1 million, respectively, at September 30, 2009. If these transactions with the same counterparty were presented on a gross basis in the Condensed Consolidated Balance Sheets, current PRM assets and liabilities would be approximately $51.8 million and $35.4 million, respectively, at December 31, 2008, and non-current PRM assets and liabilities would be approximately $105.6 million and $36.2 million, respectively, at December 31, 2008.

Reclassifications

Certain prior year amounts have been reclassified on the Condensed Consolidated Financial Statements to conform to the 2009 presentation related to the separate presentation of the noncontrolling interest in a subsidiary.

2. Fair Value Measurements

The following table is a summary of the Company's assets and liabilities that are measured at fair value on a recurring basis at September 30, 2009.

| (In millions) | Total | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|
| Assets | | | | |
| Gross derivative assets | $ 91.8 | $ 19.1 | $ 9.3 | $ 63.4 |
| Gas imbalance assets | 8.0 | --- | 8.0 | --- |
| Total | $ 99.8 | $ 19.1 | $ 17.3 | $ 63.4 |
| | | | | |
| Liabilities | | | | |
| Gross derivative liabilities | $ 75.0 | $ 14.1 | $ 59.5 | $ 1.4 |
| Gas imbalance liabilities (A) | 2.8 | --- | 2.8 | --- |
| Total | $ 77.8 | $ 14.1 | $ 62.3 | $ 1.4 |

(A) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of approximately $6.9 million, 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 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 assets or liabilities that the reporting entity has the ability to access at the measurement date. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. An example of instruments that may be classified as Level 1 includes futures transactions for energy commodities traded on the New York Mercantile Exchange ("NYMEX").

Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs include the following: (i) quoted prices for similar assets or liabilities in active markets; (ii) quoted prices for identical or similar assets or liabilities in markets that are not active; (iii) inputs other than quoted prices that are observable for the asset or liability; or (iv) inputs that are derived principally from or corroborated by observable market data by correlation or other means. 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 unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that observable inputs are not available. Unobservable inputs shall 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). Unobservable inputs shall be developed based on the best information available in the circumstances, which might include the reporting entity's own data. The reporting entity's own data used to develop unobservable inputs shall be adjusted if information is reasonably available that indicates that market participants would use different assumptions. 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 either NYMEX published market prices, independent broker pricing data or broker/dealer valuations in determining the fair value of its derivative positions. 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.

The following table is a reconciliation of the Company's total derivatives fair value to the Company's Condensed Consolidated Balance Sheet at September 30, 2009 and December 31, 2008.

| (In millions) | September 30, 2009 | December 31, 2008 |
|---|---|---|
| Assets | | |
| Gross derivative assets | $ 91.8 | $243.7 |
| Less: Amounts held in clearing broker accounts reflected in Other Current Assets | 22.6 | 86.3 |
| Less: Amounts offset under master netting agreements | 41.9 | 65.4 |
| Less: Net collateral payments from counterparties | --- | 58.1 |
| Net Price Risk Management Assets | $ 27.3 | $33.9 |
| | | |
| Liabilities | | |
| Gross derivative liabilities | $ 75.0 | $141.8 |
| Less: Amounts held in clearing broker accounts reflected in Other Current Assets | 18.8 | 70.3 |
| Less: Amounts offset under master netting agreements | 41.9 | 65.4 |
| Net Price Risk Management Liabilities | $ 14.3 | $6.1 |

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

| | Derivativ Assets | |
|---|---|---|
| (In millions) | 2009 | 20 |
| Balance at January 1 | $121.2 | $1 |
| Total gains or losses (realized/unrealized) | | |
| Included in other comprehensive income | (11.1 ) | 0 |
| Purchases, sales, issuances and settlements, net | (4.5 ) | -- |
| Balance at March 31 | $105.6 | $1 |
| Total gains or losses (realized/unrealized) | | |
| Included in earnings | --- | 0 |
| Included in other comprehensive income | (34.4 ) | (( |
| Purchases, sales, issuances and settlements, net | (3.9 ) | 1 |
| Balance at June 30 | $67.3 | $1 |
| Total gains or losses (realized/unrealized) | | |
| Included in earnings | --- | 0 |
| Included in other comprehensive income | (2.5 ) | 1 |
| Purchases, sales, issuances and settlements, net | (1.4 ) | -- |
| Balance at September 30 | $63.4 | $3 |
| The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets held at September 30 | $--- | $0 |

| | Derivative Liabilities | |
|---|---|---|
| (In millions) | 2009 | 2008 |
| Balance at January 1 | $--- | $--- |
| Total gains or losses (realized/unrealized) | | |
| Included in earnings | --- | --- |
| Included in other comprehensive income | --- | --- |
| Purchases, sales, issuances and settlements, net | --- | --- |
| Transfers in and/or out of Level 3 | --- | --- |
| Balance at March 31 | $--- | $--- |
| Total gains or losses (realized/unrealized) | | |
| Included in earnings | --- | --- |
| Included in other comprehensive income | --- | --- |
| Purchases, sales, issuances and settlements, net | 1.8 | --- |
| Transfers in and/or out of Level 3 | --- | --- |
| Balance at June 30 | $1.8 | $--- |
| Total gains or losses (realized/unrealized) | | |
| Included in earnings | --- | --- |
| Included in other comprehensive income | (0.4) | --- |
| Purchases, sales, issuances and settlements, net | --- | --- |
| Transfers in and/or out of Level 3 | --- | --- |
| Balance at September 30 | $1.4 | $--- |
| The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to liabilities held at September 30 | $--- | $--- |

Gains and losses (realized and unrealized) included in earnings for the three and nine months ended September 30, 2009 and 2008 attributable to the change in unrealized gains or losses relating to assets and liabilities held at September 30, 2009 and 2008, if any, are reported in Operating Revenues.

The following table is a summary of 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, 2009 and December 31, 2008.

| | September 30, 2009 | | December 31, 2008 | |
|---|---|---|---|---|
| (In millions) | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Price Risk Management Assets | | | | |
| Energy Derivative Contracts | $27.3 | $27.3 | $33.9 | $33.9 |
| Price Risk Management Liabilities | | | | |
| Energy Derivative Contracts | $14.3 | $14.3 | $6.1 | $6.1 |
| Long-Term Debt | | | | |
| Senior Notes | $1,505.8 | $1,650.2 | $1,505.6 | $1,420.8 |
| Industrial Authority Bonds | 135.4 | 135.4 | 135.3 | 135.3 |
| Enogex Notes | 489.0 | 533.2 | 400.9 | 436.1 |
| Enogex Revolving Credit Facility | 90.0 | 90.0 | 120.0 | 120.0 |

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 hedging and 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 management's estimate of current rates available for similar issues with similar maturities.

3. 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 commodity price futures, commodity price swap contracts and commodity price option features to manage the Company's commodity price risk exposures. The commodity price futures and commodity price swap contracts involve the exchange of fixed price or rate payments for floating price or rate payments over the life of the instrument without an exchange of the underlying commodity. The commodity price option contracts involve the payment of a premium for the right, but not the obligation, to exchange fixed price or rate payments for floating price or rate payments over the life of the instrument without an exchange of the underlying commodity. Commodity derivative instruments used by the Company are as follows:

- natural gas liquids ("NGL") put options and NGLs swaps are used to manage Enogex's NGLs exposure associated with its processing agreements;
- natural gas swaps are used to manage Enogex's keep-whole natural gas exposure associated with its processing agreements and Enogex's natural gas exposure associated with operating its gathering, transportation and storage assets;

natural gas futures and swaps and natural gas commodity purchases and sales are used to manage OGE Energy's natural gas marketing subsidiary, OGE Energy Resources, Inc.'s ("OERI"), natural gas exposure associated with its storage and transportation contracts; and

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.

Management may designate certain derivative instruments for the purchase or sale of physical commodities, purchase or sale of electric power and fuel procurement discussed above as normal purchases and normal sales contracts. 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 its 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 from time to time uses treasury lock agreements to manage its interest rate risk exposure on new debt issuances. Additionally, 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.

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. Under the change in fair value method, 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. The ineffectiveness of treasury lock cash flow hedges is measured using the hypothetical derivative method. Under the hypothetical derivative method, the Company designates that the critical terms of the hedging instrument are the same as the critical terms of the hypothetical derivative used to value the forecasted transaction, and, as a result, no ineffectiveness is expected. Forecasted transactions 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. If the forecasted transactions are no longer reasonably possible of occurring, any associated amounts recorded in Accumulated Other Comprehensive Income will also be recognized directly in earnings.

At September 30, 2009, the Company had no outstanding treasury lock agreements that were designated as cash flow hedges.

The Company designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's contractual length and operational storage natural gas, keep-whole natural gas and NGLs hedges. Enogex's cash flow hedging activity at September 30, 2009 covers the period from October 1, 2009 through 2011. The Company also designates certain derivatives used to manage commodity exposure for certain transportation and natural gas inventory positions at OERI. OERI’s cash flow hedging activity at September 30, 2009 does not extend beyond the first quarter of 2010. At September 30, 2009, the Company had the following outstanding commodity derivative instruments that were designated as cash flow hedges.

| | Commodity | Notional Volume (A) | Maturity |
|---|---|---|---|
| | | (volumes in millions) | |
| Short Financial Swaps/Futures (fixed) | NGLs | 0.5 | Current |
| Short Financial Swaps/Futures (fixed) | NGLs | 0.1 | Non-Current |
| Total Short Financial Swaps/Futures (fixed) | | 0.6 | |
| Purchased Financial Options | NGLs | 1.3 | Current |
| Purchased Financial Options | NGLs | 1.7 | Non-Current |
| Total Purchased Financial Options | | 3.0 | |
| Long Financial Swaps/Futures (fixed) | Natural Gas | 6.7 | Current |
| Long Financial Swaps/Futures (fixed) | Natural Gas | 6.7 | Non-Current |
| Total Long Financial Swaps/Futures (fixed) | | 13.4 | |
| Short Financial Swaps/Futures (fixed) | Natural Gas | 4.8 | Current |
| Short Financial Swaps/Futures (fixed) | Natural Gas | 0.5 | Non-Current |
| Total Short Financial Swaps/Futures (fixed) | | 5.3 | |
| Long Financial Basis Swaps | Natural Gas | 0.5 | Current |
| Short Financial Basis Swaps | Natural Gas | 4.8 | Current |
| Short Financial Basis Swaps | Natural Gas | 0.5 | Non-Current |
| Total Short Financial Basis Swaps | | 5.3 | |

(A) Natural gas in million British thermal unit (“MMBtu”); NGLs in barrels. All volumes are presented on a gross basis.

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, 2009, the Company had no outstanding commodity derivative instruments or treasury lock agreements that were designated as fair value hedges.

Derivatives Not Designated As Hedging Instruments

For derivative instruments that are not designated as either a cash flow or fair value hedge, the gain or loss on the derivative is recognized currently in earnings. Derivative instruments not designated as either a cash flow or a fair value hedge are utilized in OERI’s asset management, marketing and trading activities. Derivative instruments not designated as either cash flow or fair value hedges also include contracts formerly designated as cash flow hedges of Enogex’s keep-whole natural gas and NGLs 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.

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At September 30, 2009, the Company had the following outstanding commodity derivative instruments that were not designated as either a cash flow or fair value hedge.

| | Commodity | Notional Volume (A) (volumes in millions) | Maturity |
|---|---|---|---|
| Short Financial Swaps/Futures (fixed) | NGLs | 0.8 | Current |
| Short Financial Swaps/Futures (fixed) | NGLs | 0.2 | Non-Current |
| Total Short Financial Swaps/Futures (fixed) | | 1.0 | |
| Long Financial Swaps/Futures (fixed) | NGLs | 0.8 | Current |
| Long Financial Swaps/Futures (fixed) | NGLs | 0.2 | Non-Current |
| Total Long Financial Swaps/Futures (fixed) | | 1.0 | |
| Physical Purchases (B) | Natural Gas | 12.6 | Current |
| Physical Sales (B) | Natural Gas | 48.1 | Current |
| Physical Sales (B) | Natural Gas | 11.0 | Non-Current |
| Total Physical Sales | | 59.1 | |
| Long Financial Swaps/Futures (fixed) | Natural Gas | 29.9 | Current |
| Long Financial Swaps/Futures (fixed) | Natural Gas | 1.0 | Non-Current |
| Total Long Financial Swaps/Futures (fixed) | | 30.9 | |
| Short Financial Swaps/Futures (fixed) | Natural Gas | 31.7 | Current |
| Short Financial Swaps/Futures (fixed) | Natural Gas | 1.0 | Non-Current |
| Total Short Financial Swaps/Futures (fixed) | | 32.7 | |
| Purchased Financial Option | Natural Gas | 3.3 | Current |
| Sold Financial Option | Natural Gas | 3.3 | Current |
| Long Financial Basis Swaps | Natural Gas | 12.0 | Current |
| Long Financial Basis Swaps | Natural Gas | 0.3 | Non-Current |
| Total Long Financial Basis Swaps | | 12.3 | |
| Short Financial Basis Swaps | Natural Gas | 13.3 | Current |
| Short Financial Basis Swaps | Natural Gas | 0.4 | Non-Current |
| Total Short Financial Basis Swaps | | 13.7 | |

(A) Natural gas in MMBtu; NGLs in barrels. All volumes are presented on a gross basis.

(B) Of the natural gas physical purchases and sales volumes not designated as cash flow or fair value 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.

The fair value of the derivative instruments that are presented in the Company’s Condensed Consolidated Balance Sheet at September 30, 2009 are as follows:

| | | | Fair Value | |
|---|---|---|---|---|
| Instrument | Commodity | Balance Sheet Location | Assets | Liabilities |
| (dollars in millions) | | | | |
| Derivatives Designated as Hedging Instruments | | | | |
| Financial Options | NGLs | Current PRM | $ 21.0 | $ --- |
| | | Non-Current PRM | 38.4 | --- |
| Financial Futures/Swaps | NGLs | Current PRM | 1.0 | 0.2 |
| | | Non-Current PRM | 0.2 | --- |
| Financial Futures/Swaps | Natural Gas | Current PRM | 2.7 | 18.0 |
| | | Non-Current PRM | --- | 20.4 |
| | | Other Current Assets | 7.4 | 2.0 |
| Total Gross Derivatives Designated as Hedging Instruments | | | $ 70.7 | $ 40.6 |
| Derivatives Not Designated as Hedging Instruments | | | | |
| Financial Futures/Swaps (A) | NGLs | Current PRM | $ 2.3 | $ 0.9 |
| | | Non-Current PRM | 0.4 | 0.3 |
| Financial Futures/Swaps (B) | Natural Gas | Current PRM | 0.9 | 12.7 |
| | | Non-Current PRM | --- | 2.4 |
| | | Other Current Assets | 15.0 | 16.6 |
| Physical Purchases/Sales | Natural Gas | Current PRM | 1.8 | 1.3 |
| | | Non-Current PRM | 0.5 | --- |
| Financial Options | Natural Gas | Other Current Assets | 0.2 | 0.2 |
| Total Gross Derivatives Not Designated as Hedging Instruments | | | $ 21.1 | $ 34.4 |
| Total Gross Derivatives (C) | | | $ 91.8 | $ 75.0 |

(A) The fair value of Financial Futures/Swaps – NGLs not designated as hedging instruments includes derivatives that were designated as hedging instruments prior to June 30, 2009. 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. The referenced derivatives had a fair value as presented in the table above in Current Assets of approximately $2.3 million, Non-Current Assets of approximately $0.4 million, Current Liabilities of approximately $0.9 million and Non-Current Liabilities of approximately $0.3 million.

(B)

The fair value of Financial Futures/Swaps – Natural Gas not designated as hedging instruments includes derivatives that were designated as hedging instruments prior to June 30, 2009. 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. The referenced derivatives had a fair value as presented in the table above in Current Liabilities of approximately $11.5 million and Non-Current Liabilities of approximately $2.4 million.

(C) See reconciliation of the Company's total derivatives fair value to the Company's Condensed Consolidated Balance Sheet at September 30, 2009 (see Note 2).

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, 2009, the Company would have been required to post approximately $12.7 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, 2009.

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.

| Instrument | Amount of Gain or Loss Recognized in OCI on Derivative (Effective Portion)(A) | Location of Gain or Loss Reclassified from Accumulated OCI into Income (Effective Portion) | Amount of Gain or Loss Reclassified from Accumulated OCI into Income (Effective Portion) | Location of Gain or Loss Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) | Amount of Gain or Loss Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) |
|---|---|---|---|---|---|
| | | (dollars in millions) | | | |
| Derivatives in Cash Flow Hedging Relationships | | | | | |
| NGLs Financial Options | $ (2.7) | Operating Revenues | $ 0.3 | Operating Revenues | $ --- |
| NGLs Financial Futures/Swaps | (0.8) | Operating Revenues | 2.2 | Operating Revenues | --- |
| Natural Gas Financial Futures/Swaps | --- | Operating Revenues | (8.3) | Operating Revenues | 0.1 |
| Total | $ (3.5) | Total | $ (5.8) | Total | $ 0.1 |

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at September 30, 2009 that
is expected to be reclassified into earnings within the next 12 months is a loss of approximately $9.0 million.

| | Location of Gain or Loss Recognized in Income on Derivative | Amount of Gain or Loss Recognized in Income of Derivative |
|---|---|---|
| | (dollars in millions) | |
| Derivatives in Cash Flow Hedging Relationships | | |
| Natural Gas Physical Purchases/Sales | Operating Revenues | $ (8.3) |
| Natural Gas Financial Future/Swaps | Operating Revenues | 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, 2009.

| Instrument | Amount of Gain or Loss Recognized in OCI on Derivative (Effective Portion)(A) | Location of Gain or Loss Reclassified from Accumulated OCI into Income (Effective Portion) | Amount of Gain or Loss Reclassified from Accumulated OCI into Income (Effective Portion) | Location of Gain or Loss Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) | Amount of Gain or Loss Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) |
|---|---|---|---|---|---|
| | | (dollars in millions) | | | |
| Derivatives in Cash Flow Hedging Relationships | | | | | |
| NGLs Financial Options | $ (36.6) | Operating Revenues | $ 3.2 | Operating Revenues | $ --- |
| NGLs Financial Futures/Swaps | (26.0) | Operating Revenues | 12.4 | Operating Revenues | --- |
| Natural Gas Financial Futures/Swaps | (17.0) | Operating Revenues | (19.4) | Operating Revenues | (0.2) |
| Total | $ (79.6) | Total | $ (3.8) | Total | $ (0.2) |

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at September 30, 2009 that
is expected to be reclassified into earnings within the next 12 months is a loss of approximately $9.0 million.

| | Location of Gain or Loss Recognized in Income on Derivative | Amount of Gain or Loss Recognized in Income of Derivative |
|---|---|---|
| | (dollars in millions) | |
| Derivatives in Cash Flow Hedging Relationships | | |
| Natural Gas Physical Purchases/Sales | Operating Revenues | $ (18.8) |
| Natural Gas Financial Futures/Swaps | Operating Revenues | 12.7 |
| NGLs Financial Futures/Swaps | Operating Revenues | (0.2) |
| Total | | $ (6.3) |

4. Stock-Based Compensation

On January 21, 1998, the Company adopted a Stock Incentive Plan (the “1998 Plan”) and in 2003, the Company adopted another Stock Incentive Plan (the “2003 Plan” that replaced the 1998 Plan). In 2008, the Company adopted, and its shareowners approved, a new Stock Incentive Plan (the “2008 Plan” and together with the 1998 Plan and the 2003 Plan, the “Plans”). The 2008 Plan replaced the 2003 Plan and no further awards will be granted under the 2003 Plan or the 1998 Plan. As under the 2003 Plan and the 1998 Plan, under the 2008 Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees of the Company and its subsidiaries. The Company has authorized the issuance of up to 2,750,000 shares under the 2008 Plan.

The Company recorded compensation expense of approximately $1.6 million pre-tax ($1.0 million after tax, or $0.01 per basic and diluted share) and approximately $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 share-based payments. The Company recorded compensation expense of approximately $0.5 million pre-tax ($0.3 million after tax, or less than $0.01 per basic and diluted share) and approximately $3.4 million pre-tax ($2.1 million after tax, or $0.02 per basic and diluted share), respectively, during the three and nine months ended September 30, 2008 related to the Company’s share-based payments.

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, 2009, there were 90,202 shares and 252,950 shares, respectively, of new common stock issued pursuant to the Company's Plans related to exercised stock options and payouts of earned performance units. The Company received approximately $2.1 million and $7.2 million during the three months ended September 30, 2009 and 2008, respectively, and approximately $2.1 million and $14.7 million during the nine months ended September 30, 2009 and 2008, respectively, related to exercised stock options.

The Company issues restricted stock to certain existing non-officer employees as well as other executives upon hire to attract and retain individuals to be competitive in the marketplace. The restricted stock vests in one-third annual increments. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. These shares may not be sold, assigned, transferred or pledged and are subject to risk of forfeiture. The Company awarded 5,487 shares of restricted stock during both the three and nine months ended September 30, 2009. During the three and nine months ended September 30, 2009, there were 3,321 shares of restricted stock forfeited.

5. Accumulated Other Comprehensive Income (Loss)

The components of accumulated other comprehensive loss at September 30, 2009 and December 31, 2008 are as follows:

| (In millions) | September 30, 2009 | December 31, 2008 |
|---|---|---|
| Defined benefit pension plan and restoration of retirement income plan: | | |
| Net loss, net of tax (($67.8) and ($71.6) pre-tax, respectively) | $ (41.5) | $ (43.8) |
| Prior service cost, net of tax (($0.6) and ($0.8) pre-tax, respectively) | (0.4) | (0.5) |
| Defined benefit postretirement plans: | | |
| Net loss, net of tax (($11.0) and ($11.6) pre-tax, respectively) | (5.0) | (5.3) |
| Net transition obligation, net of tax (($0.7) and ($0.8) pre-tax, respectively) | (0.4) | (0.5) |
| Prior service cost, net of tax (($0.1) and ($0.3) pre-tax, respectively) | (0.1) | (0.2) |
| Deferred hedging gains (losses), net of tax (($13.8) and $62.4 pre-tax, respectively) | (8.5) | 38.1 |
| Deferred hedging losses on interest rate swaps, net of tax (($2.0) and ($2.4) pre-tax, respectively) | (1.3) | (1.5) |
| Total accumulated other comprehensive loss, net of tax | $ (57.2) | $ (13.7) |

At both September 30, 2009 and December 31, 2008, there was no accumulated other comprehensive income related to Enogex's 50 percent ownership interest in the Atoka Midstream, LLC joint venture, through Enogex Atoka, LLC, a wholly owned subsidiary of Enogex.

6. 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 or state and local income tax examinations by tax authorities for years before 2005. 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 120 megawatt ("MW") wind farm in northwestern Oklahoma. In addition, OG&E and Enogex earn Oklahoma state tax credits associated with their investment in electric generation and natural gas processing facilities which further reduce the Company's effective tax rate.

As a result of new Internal Revenue Service ("IRS") proposed regulations related to the deductibility of certain tax assets which were previously capitalized for tax reporting, on December 29, 2008, OG&E filed a request with the IRS for a change in its tax method of accounting related to the capitalization of repairs expense. The accounting method change is for income tax purposes only and would allow the Company to record a cumulative tax deduction, if approved by the IRS. For financial accounting purposes, the only change is recognition of the impact of the cash flow generated by accelerating income tax deductions. In June 2009, OG&E received a notice from the IRS indicating that its request was under review. As of October 29, 2009, OG&E had not received approval of the method.

During the third quarter of 2009, the Company filed its 2008 Federal income tax return which included approximately $211 million in net deductions related to the change of accounting method which generated a net operating loss of approximately $186 million for the 2008 tax year. Because approval for the method change has not been received, the entire asset related to the net operating loss has been accounted for as a reduction in the non-current deferred tax liability until the period in which the change of accounting method is approved. The Company believes approval from the IRS for the accounting method change is highly probable and is expected to occur by the end of 2009.

7. 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 133,427 shares and 1,901,657 shares, respectively, of common stock under the DRIP/DSPP during the three and nine months ended September 30, 2009 and received proceeds of approximately $4.0 million and $46.0 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, 2009, there were 3,098,343 shares available to be issued under the DRIP/DSPP.

Equity Issuances

From January 1, 2009 through January 28, 2009, the Company sold 1,086,100 shares of its common stock under a previous distribution agreement with J.P. Morgan Securities Inc. ("JPMS"). The Company received net proceeds from JPMS of approximately $26.9 million during this timeframe (after the JPMS commission of approximately $0.4 million) related to the sale of the shares of the Company's common stock. The Company added the net proceeds from the sale of the shares of its common stock to its general funds and used those proceeds for general corporate purposes, including the repayment of outstanding revolving credit borrowings or other short-term debt. On January 28, 2009, the Company provided written notice to JPMS of the Company's intent to terminate the distribution agreement pursuant to the terms of the distribution agreement, which termination was effective on January 29, 2009.

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) | 2009 | 2008 | 2009 | 2008 |
| Average Common Shares Outstanding | | | | |
| Basic average common shares outstanding | 96.7 | 92.6 | 96.0 | 92.2 |
| Effect of dilutive securities: | | | | |
| Employee stock options and unvested stock grants | --- | --- | --- | 0.1 |
| Contingently issuable shares (performance units) | 1.0 | 0.4 | 0.9 | 0.4 |
| Diluted average common shares outstanding | 97.7 | 93.0 | 96.9 | 92.7 |
| Anti-dilutive shares excluded from EPS calculation | --- | --- | --- | --- |

## 8. Long-Term Debt

At September 30, 2009, 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 (dollars in millions):

| SERIES | DATE DUE | AMOUNT |
|---|---|---|
| 0.30% - 1.00 % | Garfield Industrial Authority, January 1, 2025 | $ 47.0 |
| 0.42% - 0.74 % | Muskogee Industrial Authority, January 1, 2025 | 32.4 |
| 0.43% - 0.75 % | 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. OG&E believes that it has sufficient liquidity to meet these obligations.

Enogex's Refinancing of Long-Term Debt and Tender Offer

On June 24, 2009, Enogex issued $200 million of 6.875% 5-year senior notes in a transaction exempt from the registration requirements of the Securities Act of 1933. Enogex applied a portion of the net proceeds from the sale of the new notes to pay the purchase price in the tender offer discussed below for its 8.125% notes due January 2010 with the remainder of the net proceeds being used to repay a portion of Enogex's borrowings under its revolving credit agreement and for general corporate purposes. The refinancing of the balance of Enogex's 8.125% notes due January 2010 is expected to occur later in the fourth quarter of 2009. At this time, the Company cannot predict how interest rates will affect its ability to obtain financing on favorable terms.

Also on June 24, 2009, Enogex commenced a cash tender offer for up to $150 million principal amount of its 8.125% senior notes due January 2010. The tender offer for the 8.125% senior notes due January 2010 expired on July 22, 2009. The total consideration per $1,000 principal amount of the 8.125% senior notes due January 2010 validly tendered and not withdrawn was $1,027.50. Pursuant to the tender offer, on July 23, 2009, Enogex purchased approximately $110.8 million principal amount of the 8.125% senior notes due January 2010 and those repurchased notes were retired and cancelled.

9. Short-Term Debt

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by loans under short-term bank facilities. The short-term debt balance was approximately $308.0 million and $298.0 million at September 30, 2009 and December 31, 2008, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at September 30, 2009.

Revolving Credit Agreements and Available Cash (In millions)

| Entity | Aggregate Commitment | Amount | Weighted-Average Interest Rate | Maturity |
|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | Outstanding (A) | | |
| OGE Energy (B) | $ | 596.0 | $ | 308.0 | 0.43% (D) | December 6, 2012 |
| OG&E (C) | | 389.0 | | 11.1 | ---% (D) | December 6, 2012 |
| Enogex (E) | | 250.0 | | 90.0 | 0.57% (D) | March 31, 2013 |
| | | 1,235.0 | | 409.1 | 0.46% | |
| Cash | | 2.3 | | N/A | N/A | N/A |
| Total | $ | 1,237.3 | $ | 409.1 | 0.46% | |

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at September 30, 2009.

(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, 2009, there was approximately $149.0 million in outstanding borrowings under this revolving credit agreement and approximately $159.0 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, 2009, there was approximately $11.1 million supporting letters of credit. There were no outstanding borrowings under this revolving credit agreement and no outstanding commercial paper borrowings at September 30, 2009.

(D) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements and commercial paper borrowings.
(E) This bank facility is available to provide revolving credit borrowings for Enogex. At September 30, 2009, there was approximately $90.0 million in outstanding borrowings under this revolving credit agreement. These borrowings are not expected to be repaid within the next 12 months, therefore, they are classified as long-term debt for financial reporting purposes.

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 back-up lines of credit could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrades of the ratings of OGE Energy or OG&E would result in an increase in the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes. Any future downgrade of the Company would 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. In addition, OGE Energy is the credit support provider for OERI and any downgrade below investment grade of OGE Energy may require OGE Energy to post cash collateral or letters of credit to support OERI's asset management, marketing and trading activities and hedging activities executed on behalf of Enogex.

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.

10. 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) | 2009 (A) | 2008 (A) | 2009 (B) | 2008 (B) |
| Service cost | $ 4.6 | $ 4.7 | $ 13.6 | $ 14.2 |
| Interest cost | 7.8 | 7.9 | 23.5 | 23.5 |
| Return on plan assets | (8.2) | (11.0) | (24.7) | (32.8) |
| Amortization of net loss | 5.8 | 2.4 | 17.6 | 7.0 |
| Amortization of unrecognized prior service cost | 0.2 | 0.2 | 0.6 | 0.7 |
| Net periodic benefit cost | $ 10.2 | $ 4.2 | $ 30.6 | $ 12.6 |

| | Restoration of Retirement Income Plan | | | |
|---|---|---|---|---|
| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| (In millions) | 2009 (A) | 2008 (A) | 2009 (B) | 2008 (B) |
| Service cost | $ 0.1 | $ 0.2 | $ 0.5 | $ 0.6 |
| Interest cost | 0.1 | 0.1 | 0.3 | 0.3 |
| Amortization of net loss | 0.1 | 0.1 | 0.2 | 0.2 |
| Amortization of unrecognized prior service cost | 0.2 | 0.2 | 0.5 | 0.5 |
| Net periodic benefit cost | $ 0.5 | $ 0.6 | $ 1.5 | $ 1.6 |

(A) In addition to the $10.7 million and $4.8 million of net periodic benefit cost recognized during the three months ended September 30, 2009 and 2008, respectively, OG&E recognized the following:

a reduction in pension expense during the three months ended September 30, 2009 of less than $0.1 million and an increase in pension expense during the three months ended September 30, 2008 of approximately $2.6 million, respectively, 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 $32.1 million and $14.2 million of net periodic benefit cost recognized during the nine months ended September 30, 2009 and 2008, respectively, OG&E recognized the following:

- a reduction in pension expense during the nine months ended September 30, 2009 of approximately $2.2 million and an increase in pension expense during the nine months ended September 30, 2008 of approximately $7.6 million, respectively, 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
- a reduction in pension expense during the nine months ended September 30, 2009 of approximately $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) | 2009 | 2008 | 2009 | 2008 |
| Service cost | $0.8 | $1.0 | $2.5 | $2.8 |
| Interest cost | 3.6 | 3.3 | 10.6 | 10.0 |
| Return on plan assets | (1.6) | (1.6) | (4.9) | (4.9) |
| Amortization of transition obligation | 0.7 | 0.7 | 2.1 | 2.1 |
| Amortization of net loss | 1.2 | 1.0 | 3.7 | 3.0 |
| Amortization of unrecognized prior service cost | 0.2 | 0.4 | 0.7 | 1.4 |
| Net periodic benefit cost | $4.9 | $4.8 | $14.7 | $14.4 |

Pension Plan Funding

In the third quarter of 2009, the Company contributed approximately $10 million to its pension plan for a total contribution of approximately $50 million to its pension plan during 2009. No additional contributions are expected in 2009.

11. 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, 2009 and 2008.

| Three Months Ended September 30, 2009 | Electric Utility | Transportation and Storage | Gathering and Processing | Marketing | Other Operations | Eliminations | Total |
|---|---|---|---|---|---|---|---|
| (In millions) | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 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 | 11.3 | --- | 2.8 | --- | 66.6 |
| Impairment of assets | --- | --- | 0.6 | --- | --- | --- | 0.6 |
| 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 |

| Three Months Ended September 30, 2008 (In millions) | Electric Utility | Transportation and Storage | Gathering and Processing | Marketing | Other Operations | Eliminations | Total |
|---|---|---|---|---|---|---|---|
| Operating revenues | $ 682.5 | $ 176.0 | $ 313.0 | $ 394.9 | $ --- | $ (312.1) | $ 1,254.3 |
| Cost of goods sold | 380.9 | 130.0 | 250.8 | 385.7 | --- | (310.6) | 836.8 |
| Gross margin on revenues | 301.6 | 46.0 | 62.2 | 9.2 | --- | (1.5) | 417.5 |
| Other operation and maintenance | 79.9 | 12.3 | 22.2 | 2.7 | (2.1) | (1.4) | 113.6 |
| Depreciation and amortization | 37.7 | 4.4 | 9.5 | --- | 1.8 | --- | 53.4 |
| Taxes other than income | 14.4 | 3.1 | 1.1 | --- | 0.7 | --- | 19.3 |
| Operating income (loss) | $ 169.6 | $ 26.2 | $ 29.4 | $ 6.5 | $ (0.4) | $ (0.1) | $ 231.2 |
| Total assets | $ 4,807.8 | $ 1,211.3 | $ 743.0 | $ 188.6 | $ 2,538.7 | $ (3,120.2) | $ 6,369.2 |

| 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 | 138.8 | 15.2 | 32.0 | --- | 7.8 | --- | 193.8 |
| Impairment of assets | 0.3 | 0.8 | 0.9 | --- | --- | --- | 2.0 |
| 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 |

| Nine Months Ended September 30, 2008 (In millions) | Electric Utility | Transportation and Storage | Gathering and Processing | Marketing | Other Operations | Eliminations | Total |
|---|---|---|---|---|---|---|---|
| Operating revenues | $ 1,589.6 | $ 519.2 | $ 890.7 | $ 1,317.8 | $ --- | $ (932.6) | $ 3,384.7 |
| Cost of goods sold | 934.2 | 404.4 | 690.2 | 1,307.4 | --- | (928.5) | 2,407.7 |
| Gross margin on revenues | 655.4 | 114.8 | 200.5 | 10.4 | --- | (4.1) | 977.0 |
| Other operation and maintenance (A) | 260.0 | 37.0 | 64.6 | 8.4 | (7.8) | (4.4) | 357.8 |
| Depreciation and amortization | 110.9 | 12.8 | 27.1 | 0.1 | 5.6 | --- | 156.5 |
| Taxes other than income | 44.9 | 9.7 | 3.3 | 0.3 | 2.5 | --- | 60.7 |
| Operating income (loss) | $ 239.6 | $ 55.3 | $ 105.5 | $ 1.6 | $ (0.3) | $ 0.1 | $ 402.0 |
| Total assets | $ 4,807.8 | $ 1,211.3 | $ 743.0 | $ 188.6 | $ 2,538.7 | $ (3,120.2) | $ 6,369.2 |

(A) In 2004, the Company adopted a standard costing model utilizing a fully loaded activity rate (including payroll, benefits, other employee related costs and overhead costs) to be applied to projects eligible for capitalization or deferral. In March 2008, the Company determined that the application of the fully loaded activity rates had unintentionally resulted in the over capitalization of immaterial amounts of certain payroll, benefits, other employee related costs and overhead costs in prior years. To correct this issue, in March 2008, the Company recorded a pretax charge of approximately $9.5 million ($5.8 million after tax, or $0.06 per basic and diluted share) as an increase in Other Operation and Maintenance Expense in the Condensed Consolidated Statements of Income for the three months ended March 31, 2008 and a corresponding $8.6 million decrease in Construction Work in Progress and $0.9 million decrease in Other Deferred Charges and Other Assets related to the regulatory asset associated with storm costs in the Condensed Consolidated Balance Sheets as of March 31, 2008.

12. Commitments and Contingencies

Except as set forth below and in Note 13, the circumstances set forth in Notes 15 and 16 to the Company's Consolidated Financial Statements included in the Company's 2008 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 December 31, 2008, OG&E had a noncancellable operating lease with purchase options, covering 1,464 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 value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of approximately $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 expires with respect to 135 railcars on March 5, 2010. The lease agreement with respect to the remaining 135 railcars will expire on November 2, 2009, six months from the date those railcars entered OG&E's service on May 2, 2009.

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.

OG&E Coal Transportation Contracts

OG&E has transportation contracts for the transportation of coal to its coal-fired power plants. OG&E's transportation contracts expired on December 31, 2008. On December 19, 2008, OG&E entered into a new rail transportation agreement with the BNSF Railway for the movement of coal to OG&E's Sooner power plant. The rates in the new agreement were higher than the rates in OG&E's previous transportation contracts.

OG&E also filed a complaint at the Surface Transportation Board ("STB") requesting the establishment of reasonable rates, practices and service terms for the transportation of coal from Union Pacific served mines in the southern Powder River Basin, Wyoming to OG&E's Muskogee power plant. OG&E began paying interim shipping rates, subject to refund, while this matter was pending with the STB. On July 24, 2009 the STB issued a decision awarding OG&E a reduction in interim shipping rates to its Muskogee plant. In September 2009, OG&E received a refund of approximately $2.7 million from Union Pacific related to payments OG&E made in the first quarter of 2009. OG&E expects to receive additional refunds for payments it made in the second and third quarters of 2009 by the end of 2009. All refund amounts will be passed through to OG&E's customers.

The overall effect of the new BNSF Railway agreement and rail rate prescription from the STB for rail transportation to OG&E's Sooner and Muskogee power plants is expected to cause an approximate 47 percent annual increase in OG&E's delivered coal prices.

OG&E Termination of Wholesale Agreement

On May 28, 2009, OG&E sent a termination notice to the Arkansas Valley Electric Cooperative ("AVEC") that OG&E would terminate its wholesale power agreement to all points of delivery where OG&E sells or has sold power to AVEC, effective November 30, 2011. OG&E is in the process of discussing an agreement with AVEC which could result in OG&E supplying wholesale power to AVEC from December 1, 2011 through December 31, 2014. Any such agreement would be conditioned on the FERC and state regulatory approvals. The termination of the AVEC agreement is not expected to have a material impact to the Company's consolidated financial position or results of operations.

Natural Gas Units

In August 2009, OG&E issued a request for proposal ("RFP") for gas supply purchases for periods from November 2009 through March 2010. The gas supply purchases from January through March 2010 account for approximately 15 percent of OG&E's projected 2010 natural gas requirements. The RFP process was completed on September 10, 2009. The contracts resulting from this RFP are tied to various gas price market indices that will expire in 2010. Additional gas supplies to fulfill OG&E's remaining 2010 natural gas requirements will be acquired through additional RFPs in early to mid-2010, along with monthly and daily purchases, all of which are expected to be made at market prices.

Coal

In August 2009, OG&E issued an RFP for coal supply purchases for periods from January 2011 through December 2015. The coal supply purchases account for approximately 50 percent of OG&E's projected coal requirements during that timeframe. The RFP process is expected to be completed during the fourth quarter of 2009. Additional coal supplies to fulfill OG&E's remaining 2010 through 2015 coal requirements will be acquired through additional RFPs, which are expected to be made at market prices.

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. OG&E filed a writ of prohibition at the Oklahoma Supreme Court asking the court to direct the trial court to dismiss the class action suit. 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 authorized OG&E to collect the challenged franchise fee charges. A procedural schedule and notice requirements for the matter were established by the OCC on December 4, 2008. On March 10, 2009, the Oklahoma Attorney General, OG&E, OG&E Shareholders Association and the Staff of the Public Utility Division of the OCC all filed briefs arguing that the application should be dismissed. A hearing on the motions to dismiss was held before an administrative law judge ("ALJ") on March 26, 2009. On June 30, 2009, the ALJ issued a report recommending that the application be dismissed. On July 9, 2009, the applicants filed a Notice of Appeal and a hearing on this matter is scheduled for November 5, 2009. OG&E believes that this case is without merit.

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. The cause of the rupture is not known and an investigation of the incident is ongoing. The damaged pipeline has been repaired and the pipeline is back in service. After the incident, Enogex coordinated with and assisted the affected residents. Enogex resolved matters with two of the residents and Enogex continues 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 seeking to recover actual and punitive damages. The parties participated in a mediation of the pending action in August but were unable to resolve the action. While the Company cannot predict the outcome of this lawsuit at this time, the Company intends to vigorously defend this case and believes that its ultimate resolution will not be material to the Company's consolidated financial position or results of operations.

Agreement with Midcontinent Express Pipeline, LLC

In December 2006, Enogex entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC ("MEP") for a primary term of ten years (subject to possible extension) that would give MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP lease agreement is currently 272 million cubic feet per day, with the quantity ultimately to be leased subject to being increased by mutual agreement pursuant to the lease agreement. In addition to MEP's lease of Enogex's capacity, the MEP project included construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Enogex's capital expenditures related to this project were approximately $99 million.

On July 25, 2008, the FERC issued its order approving the MEP project including the approval of a limited jurisdiction certificate authorizing the Enogex lease agreement to MEP. Further, the FERC order rejected 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, one protestor filed a request for rehearing. The FERC denied the request for rehearing, and Enogex commenced service to MEP under the lease agreement on June 1, 2009. On July 16, 2009, the protestor filed a petition for review of the FERC's orders before the United States Court of Appeals for the District of Columbia Circuit requesting that the orders be modified or set aside on the grounds that they are arbitrary, capricious and contrary to law. The petitioner, the FERC and interested parties that have sought intervenor status will be given an opportunity to brief the issues. Enogex has filed its intervention and expects to participate in the filing of a joint intervenors' brief in support of the FERC's order in this matter. On October 27, 2009, the Court of Appeals issued an order establishing the briefing schedule for the proceeding which provides for the briefing to be completed in the first quarter of 2010.

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

In 2004, OERI entered into a Firm Transportation Service Agreement ("FTSA") with Cheyenne Plains Pipeline Company, L.L.C. ("Cheyenne Plains"), who operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas, for 60,000 decatherms/day ("Dth/day") of firm capacity on the pipeline. The FTSA was for a 10-year term beginning with the in-service date of the Cheyenne Plains Pipeline in March 2005 with an annual demand fee of approximately $7.4 million. Effective March 1, 2007, OERI and Cheyenne Plains amended the FTSA to provide for OERI to turn back 20,000 Dth/day of its capacity beginning in January 2008 for the remainder of the term. Additionally, in March 2009, OERI entered into two agreements to release to a third party 10,000 Dth/day of its remaining capacity beginning in April 2009 through December 2009. OERI's new demand fee obligations, net of this turn back, prior turn backs and other immaterial release agreements, are estimated at approximately $3.7 million for 2009; $5.4 million for each of the years 2010 through 2012; $6.5 million for each of the years 2013 and 2014 and $1.6 million in 2015.

Natural Gas Measurement Cases

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

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

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

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

On October 20, 2006, the District Court of Wyoming ruled on Grynberg's district court appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex Services Corp., Transok, Inc. ("Transok") and OG&E, for lack of subject matter jurisdiction.  Judgment was entered on November 17, 2006.  The defendants filed motions for attorneys' fees and other legal costs on various bases.  A hearing on these motions was held on April 24, 2007, at which time the judge took these motions under advisement.  On November 15, 2006, Grynberg filed appeals with the Tenth Circuit Court of Appeals.  On March 17, 2009, the Tenth Circuit Court of Appeals affirmed the October 2006 order of the District Court of Wyoming dismissing the complaints against all gas defendants, including all Company parties.  On April 14, 2009, Grynberg filed a petition for rehearing in the Tenth Circuit Court of Appeals.  By order dated May 4, 2009, the Tenth Circuit Court denied Grynberg's request for rehearing. Grynberg filed a petition for writ of certiorari in the U.S. Supreme Court on August 3, 2009. By order dated October 5, 2009, the U.S. Supreme Court denied Grynberg's petition for writ of certiorari. This ruling concludes the appeal of the October 2006 order of the District Court of Wyoming dismissing complaints against all gas defendants, including all Company parties. The Company now considers this case closed and, as a result, during the third quarter of 2009, Enogex reversed a reserve of approximately $1.5 million that was originally established with the 1999 acquisition of Transok.

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 subsidiary entities remained as defendants. The plaintiffs' Fourth Amended Petition seeks class certification and alleges that approximately 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 reconsideration of the court's denial of class certification.

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.

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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.

Environmental Laws and Regulations

Air

On March 15, 2005, the U.S. Environmental Protection Agency ("EPA") issued the Clean Air Mercury Rule ("CAMR") to limit mercury emissions from coal-fired boilers. On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit Court vacated the rule. The EPA has stated that it intends to draft new mercury rules under the Federal Clean Air Act. Any costs associated with future mercury regulations are uncertain at this time. Because of the uncertainty caused by the litigation regarding the CAMR, the promulgation of an Oklahoma rule that would have applied to existing facilities has also been delayed. OG&E will continue to participate in the state rule making process.

On March 5, 2009, the 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 ("RICE MACT Amendments"). Depending on the final regulations that may be enacted by the EPA for the RICE MACT Amendments, Enogex and OG&E facilities will likely be impacted. The costs that may be incurred to comply with these regulations, including the testing and modification of the affected engines, are uncertain at this time. The current proposed compliance deadline is three years from the effective date of the final rules.

On April 25, 2005, the EPA published a finding that all 50 states failed to submit the interstate pollution transport plans required by the Clean Air Act as a result of the adoption of the revised ambient ozone and fine particle standards. Failure to submit these implementation plans began a two-year timeframe, starting on May 25, 2005, during which states must submit a demonstration to the EPA that they do not affect air quality in downwind states. The demonstration was properly submitted by the state to the EPA on May 7, 2007, and additional information was submitted by the state to the EPA on December 5, 2007. Because the EPA had not yet approved Oklahoma's submittal, a third party filed a lawsuit against the EPA in an attempt to force them to act. The outcome of this matter is uncertain at this time.

In September 2005, the Oklahoma Department of Environmental Quality ("ODEQ") informally notified affected utilities that they would be required to perform a study to determine their impact on visibility in Federal Class I areas. Affected utilities are those which have sources built between 1962 and 1977. These sources must evaluate the installation of Best Available Retrofit Technology ("BART") to address regional haze. For OG&E, the BART-eligible sources include various generating units at various generating stations. The 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 is expected to be included in the ODEQ state implementation plan ("SIP") for regional haze.

Waivers were not available for the BART-eligible units at the Seminole, Muskogee and Sooner generating stations. OG&E submitted a BART compliance plan for Seminole on March 30, 2007 committing to installation of nitrogen oxide ("NOX") controls on all three units. At the same time, OG&E submitted a determination to the ODEQ that an alternative compliance plan for the affected units at the Muskogee and Sooner power plants. The cost for this alternative compliance plan, including the BART compliance plan for the Seminole power plant (the alternative compliance plan and the BART compliance plan are collectively referred to herein as the "alternative plan"), was estimated at approximately $470 million in March 2007. This alternative plan was subject to approval by the ODEQ and the EPA. On November 16, 2007, the ODEQ notified OG&E that additional analysis would be required before the OG&E alternative plan could be accepted. On May 30, 2008, OG&E filed the results with the ODEQ for the affected generating units. 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 its four coal-fired generating units at its

Muskogee and Sooner generating stations. The capital expenditures associated with the installation of the low NOX combustion technology are expected to be approximately $110 million. OG&E believes that these control measures will achieve visibility improvements in a cost-effective manner. OG&E did not propose the installation of scrubbers at its 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 $1.7 billion) would not be cost-effective. The ODEQ has not taken formal action to approve or deny OG&E's plan. OG&E is currently in discussions with the ODEQ on what requirements can be included in the SIP as OG&E's BART compliance plan. The original deadline for the ODEQ to submit a SIP for regional haze that includes final BART determinations was December 17, 2007. The ODEQ did not meet this deadline. On January 15, 2009, the EPA published a rule that gives the ODEQ two years to complete the SIP. If the ODEQ fails to meet this deadline, the EPA can issue a Federal implementation plan. Until the BART determination is approved, 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 environmental expenditures will qualify as part of a pre-approval plan to handle state and federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E's retail customers under House Bill 1910, which was enacted into law in May 2005. The EPA Region 6 has commented on the submission. The EPA agreed that good combustion techniques are BART for NOX, but the EPA asked OG&E to take a voluntary limit on the availability of the units at Seminole to be consistent with the modeling in the analysis. With respect to the proposal that low sulfur coal is BART for sulfur dioxide ("SO2"), the EPA Region 6 raised two issues. First, the EPA questioned whether the cost projections in the BART analysis continue to be accurate in light of subsequent regulatory and economic developments that could lower demand for scrubbers. Second, the EPA suggested that the projected costs are not "a compelling reason" not to require the installation of scrubbers. OG&E has subsequently communicated to the ODEQ that recent cost information shows that OG&E's previous BART analysis is still accurate.

In September 2009, OG&E updated its BART analysis with regard to the cost-effectiveness of scrubbers. This revised analysis (in accordance with the EPA precedent) demonstrated that scrubbers were even less cost-effective than previously shown. In addition, on September 23, 2009, OG&E proposed an alternative plan for addressing regional haze compliance. This plan involves short-term changes to the dispatching of OG&E's coal units in a way to minimize SO2 emissions and a longer term commitment to achieve reductions that would equate with scrubber installation. This alternative plan would be less expensive than immediate installation of scrubbers and would allow OG&E time to consider various other anticipated environmental regulation and legislation before deciding whether to install costly scrubbers. On October 5, 2009, the ODEQ circulated a draft SIP to the Federal land managers with the Bureau of Land Management overseeing the various federal national parks and wildlife areas impacted by regional haze. This SIP suggested that scrubbers would be needed to comply with the regional haze regulations, but noted OG&E's new cost-effectiveness analysis and its alternative plan. OG&E continues to advocate for its alternative proposal before the ODEQ, the EPA and the Federal land managers. The Federal land managers will review the SIP for 60 days and the SIP will also be subject to a 30-day public review period before the final filing with the EPA, which is expected to occur in January 2010.

Currently, the EPA has designated Oklahoma "in attainment" with the ambient standard for ozone of 0.08 parts per million ("PPM"). In March 2008, the EPA lowered the ambient primary and secondary standards to 0.075 PPM. Oklahoma had until March 2009 to designate any areas of non-attainment within the state, based on ozone levels in 2006 through 2008. Following the state's designation, the EPA was expected to determine a final designation by March 2010. States were to be required to meet the ambient standards between 2013 and 2030, with deadlines depending on the severity of their ozone level. Oklahoma City and Tulsa were the most likely areas to be designated non-attainment in Oklahoma. On September 16, 2009, the EPA announced that they would reconsider the 2008 national primary and secondary ozone standards to ensure they are scientifically sound and protective of human health. The EPA plans to propose any revisions to the ozone standards by December 2009 and expects to issue a final decision by August 2010. The EPA also proposed to keep the 2008 standards unchanged for the purpose of attainment and non-attainment area designations. The Company cannot predict the final outcome of this evaluation or its timing or affect on OG&E's or Enogex's operations.

There also is growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation and regulation at the Federal level, actions at the state level, litigation relating to greenhouse gas emissions and pressure for greenhouse gas emission reductions from investor organizations and the international community. Recently, two Federal courts of appeal have reinstated nuisance-type claims against emitters of carbon dioxide, including several utility companies, alleging that such emissions contribute to global warming. On April 17, 2009, the EPA issued a proposed finding that greenhouse gases contribute to air pollution that may endanger public health or welfare. The proposed finding identified six greenhouse gases that pose a potential threat: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride. The EPA is considering public comments on the proposed finding. On September 15, 2009, the EPA proposed rules to reduce greenhouse gas emissions from light-duty vehicles. Final adoption of the proposed standards for light-duty vehicles is contingent on the EPA first finalizing its proposed endangerment finding for greenhouse gas emissions from motor vehicles.

In June 2009, the American Clean Energy and Security Act of 2009 (sometimes referred to as the Waxman-Markey global climate change bill) was passed in the U.S. House of Representatives. The bill includes many provisions that would potentially have a significant impact on the Company and its customers. The bill proposes a cap and trade regime, a renewable portfolio standard, electric efficiency standards, revised transmission policy and mandated investments in plug-in hybrid infrastructure and smart grid technology. Although proposals have been introduced in the U.S. Senate, including a proposal that would require greater reductions in greenhouse gas emissions than the American Clean Energy and Security Act of 2009, it is uncertain at this time whether, and in what form, legislation will be adopted by the U.S. Senate. Both President Obama and the Administrator of the EPA have repeatedly indicated their preference for comprehensive legislation to address this issue and create the framework for a clean energy economy. Compliance with any new laws or regulations regarding the reduction of greenhouse gases could result in significant changes to the Company's operations, significant capital expenditures by the Company and a significant increase in its cost of conducting business.

On September 22, 2009, the EPA announced the adoption of the first comprehensive national system for reporting emissions of carbon dioxide and other greenhouse gases produced by major sources in the United States. The new reporting requirements will apply to suppliers of fossil fuel and industrial chemicals, manufacturers of motor vehicles and engines, as well as large direct emitters of greenhouse gases with emissions equal to or greater than a threshold of 25,000 metric tons per year, which includes certain OG&E and Enogex facilities. The rule requires the collection of data beginning on January 1, 2010 with the first annual reports due to the EPA on March 31, 2011. Certain reporting requirements included in the initial proposed rules that may have significantly affected capital expenditures were not included in the final reporting rule. Additional requirements have been reserved for further review by the EPA with additional rulemaking possible. The outcome of such review and cost of compliance of any additional requirements is uncertain at this time.

On September 30, 2009, the EPA proposed two rules related to the control of greenhouse gas emissions. The first proposal, which is related to the prevention of significant deterioration and Title V tailoring, determines what sources would be affected by requirements under the Federal Clean Air Act programs for new and modified sources to control emissions of carbon dioxide and other greenhouse gas emissions. The second proposal addresses the December 2008 prevention of significant deterioration interpretive memo by the EPA, which declared that carbon dioxide is not covered by the prevention of significant deterioration provisions of the Federal Clean Air Act. The outcome of these proposals is uncertain at this time.

Oklahoma and Arkansas have not, at this time, established any mandatory programs to regulate carbon dioxide and other greenhouse gases. However, government officials in these states have declared support for state and Federal action on climate change issues. OG&E reports quarterly its carbon dioxide emissions and is continuing to evaluate various options for reducing, avoiding, off-setting or sequestering its carbon dioxide emissions. Enogex is a partner in the EPA Natural Gas STAR Program, a voluntary program to reduce methane emissions. 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 on generation facilities to address climate change, this could result in significant additional compliance costs that would affect our future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

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 a draft permit for review on January 9, 2009. OG&E provided comments on the draft permit and will provide additional comments during the public comment period. In addition, OG&E filed OPDES permit renewal applications for its Muskogee and Mustang generating stations on March 4, 2009 and April 3, 2009, respectively.

Section 316(b) of the Federal Resource Conservation and Recovery Act and the Federal Water Pollution Control Act of 1972, as amended ("Clean Water Act") requires that the locations, design, construction and capacity of any cooling water intake structure reflect the "best available technology" for minimizing environmental impacts. The EPA Section 316(b) rules for existing facilities became effective July 23, 2004. On January 25, 2007, a Federal court reversed and remanded certain portions of the Section 316(b) rules to the EPA. On July 9, 2007, the EPA suspended these portions of the Section 316(b) rules for existing facilities. As a result of such suspension, permits required for existing facilities are to be developed by the individual states using their best professional judgment until the EPA completes its review of the suspended sections. In September 2007, the state of Oklahoma required a comprehensive demonstration study be submitted by January 7, 2008 for each affected facility. On January 7, 2008, OG&E submitted the requested studies for facilities. Additionally, on April 14, 2008, the U.S. Supreme Court granted writs of certiorari to review the question of whether the Section 316(b) rules authorize the EPA to compare costs with benefits in determining the best technology available for minimizing "adverse environmental impact" at cooling water intake structures. On April 1, 2009, the U.S. Supreme Court held that the EPA has discretion to consider costs relative to benefits in developing cooling water intake structure regulations under Section 316(b) of the Clean Water Act. It was originally anticipated that the State of Oklahoma, using its best professional judgment, would develop Section 316(b) permit requirements prior to any EPA proposal of rules based on the U.S. Supreme Court decision. At the Company's request, Oklahoma may not require implementation of 316(b) requirements prior to the EPA developing and finalizing their rules. As a result of the EPA's final 316(b) rules, and the state's subsequent adoption and implementation, OG&E may require additional capital and/or increased operating costs associated with cooling water intake structures at its generating facilities.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Condensed Consolidated Financial Statements. Except as otherwise stated above, in Note 13 below, in Item 1 of Part II of this Form 10-Q, in Notes 15 and 16 of Notes to the Company's Consolidated Financial Statements included in the Company's 2008 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.

13. Rate Matters and Regulation

Except as set forth below, the circumstances set forth in Note 16 to the Company's Consolidated Financial Statements included in the Company's 2008 Form 10-K appropriately represent, in all material respects, the current status of any regulatory matters.

Completed Regulatory Matters

OG&E Arkansas Rate Case Filing

On August 29, 2008, OG&E filed with the APSC an application for an annual rate increase of approximately $26.4 million to recover, among other things, costs for investments including the 1,230 MW natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma and improvements in its system of power lines, substations and related equipment to ensure that OG&E can reliably meet growing customer demand for electricity. On March 18, 2009, OG&E, the APSC Staff and the Arkansas Attorney General filed a settlement agreement in this matter calling for a general rate increase of approximately $13.6 million. This settlement agreement also allows implementation of OG&E's "time-of-use" tariff which allows participating customers to save on their electricity bills by shifting some of the electricity consumption to times when demand for electricity is lowest. On May 20, 2009, the APSC approved a general rate increase of approximately $13.3 million, which excludes approximately $0.3 million in storm costs discussed below. OG&E implemented the new electric rates effective June 1, 2009.

OG&E 2008 Arkansas Storm Cost Filing

On October 30, 2008, OG&E filed an application with the APSC requesting authority to defer its 2008 storm costs that exceed the amount recovered in base rates. The application also requested the APSC to provide for recovery of the deferred 2008 storm costs in OG&E's pending rate case. On December 19, 2008, the APSC issued an order authorizing OG&E to defer approximately $0.6 million in 2008 for incremental storm costs in excess of the amount included in OG&E's rates. As discussed above, on March 18, 2009, OG&E, the APSC Staff and the Arkansas Attorney General reached a settlement agreement in OG&E's Arkansas rate case which included recovery of these storm costs. As discussed above, in its May 20, 2009 order approving the settlement agreement, the APSC directed OG&E to file an exact recovery rider for its 2008 storm costs. OG&E filed this recovery rider and the rider was implemented June 1, 2009.

OG&E System Hardening Filing

In December 2007, a major ice storm affected OG&E's service territory which resulted in a large number of customer outages. The OCC requested its Staff to review and determine if a rulemaking was warranted. The OCC Staff issued numerous data requests and is in the process of determining if other regulatory jurisdictions have policies or rules requiring that electric transmission and distribution lines be placed underground. The OCC Staff also surveyed customers. On June 30, 2008, the OCC Staff submitted a report entitled, "Inquiry into Undergrounding Electric Facilities in the State of Oklahoma." OG&E formed a plan to place facilities underground (sometimes referred to as system hardening) with capital expenditures of approximately $115 million over five years for underground facilities, as well as $10 million annually for enhanced vegetation management. On December 2, 2008, OG&E filed an application with the OCC requesting approval of its proposed system hardening plan with a recovery rider. On March 20, 2009, all parties to this case signed a settlement agreement recommending a three-year plan that includes up to $35.3 million in capital expenditures and approximately $33.2 million in operating expenses for aggressive vegetation management and a recovery rider. On May 13, 2009, the OCC issued an order approving the settlement agreement in this matter. The new rider, which will allow OG&E to recover costs related to system hardening incurred on or after June 15, 2009, was implemented July 1, 2009.

Security Enhancements

On January 15, 2009, OG&E filed an application with the OCC to amend its security plan. OG&E is seeking approval of new security projects and cost recovery through the previously authorized security rider. The annual revenue requirement is approximately $0.9 million. On May 29, 2009, the OCC issued an order approving a settlement agreement in this matter that incorporated OG&E's requested rate relief. The new rider was implemented June 1, 2009.

OG&E FERC Formula Rate Filing

On November 30, 2007, OG&E made a filing at the FERC to increase its transmission rates to wholesale customers moving electricity on OG&E's transmission lines. Interventions and protests were due by December 21, 2007. While several parties filed motions to intervene in the docket, only the Oklahoma Municipal Power Authority ("OMPA") filed a protest to the contents of OG&E's filing. OG&E filed an answer to the OMPA's protest on January 7, 2008. On January 31, 2008, the FERC issued an order (i) conditionally accepting the rates; (ii) suspending the effectiveness of such rates for five months, to be effective July 1, 2008, subject to refund; (iii) establishing hearing and settlement judge procedures; and (iv) directing OG&E to make a compliance filing. In July 2008, rates were implemented in an annual increase of approximately $2.4 million, subject to refund. On April 24, 2009, OG&E and the OMPA filed a settlement agreement with the FERC containing certain revisions to the formula template and protocols for conducting annual updates of wholesale transmission rates. The proposed settlement provides for a $1.3 million increase in revenues from OG&E's transmission customers compared to the $2.4 million increase in revenues previously implemented in July 2008. On May 11, 2009, OG&E and the Southwest Power Pool ("SPP") made a joint filing with the FERC to implement the settlement agreement on an interim basis effective as of May 1, 2009 pending formal action on the settlement agreement by the FERC. The joint motion for interim implementation was granted by the Chief Judge on May 20, 2009. On June 25, 2009, the FERC issued an order approving OG&E's settlement agreement. OG&E expects to refund any over collections to its transmission customers beginning in 2010.

OG&E 2009 Oklahoma Rate Case Filing

On February 27, 2009, OG&E filed its rate case with the OCC requesting a rate increase of approximately $110 million. A procedural schedule was established on April 29, 2009 and a preliminary settlement conference was held on June 25 and 26, 2009. On July 2, 2009, OG&E announced that it had filed a settlement agreement with the OCC Staff, the Attorney General's Office of Oklahoma, the Oklahoma Industrial Energy Consumers and other intervenors resolving all issues associated with its requested rate increase. The settlement agreement calls for: (i) an annual net increase of approximately $48.3 million in OG&E's rates to its Oklahoma retail customers, which includes an increase in the residential customer charge from $6.50/month to $13.00/month; (ii) creation of a new recovery rider to permit the recovery of up to $20 million of capital expenditures and operation and maintenance expenses associated with OG&E's smart grid project in Norman, Oklahoma, effective upon completion of the project, which is currently scheduled for July 2010; (iii) continued utilization of an return on equity ("ROE") of 10.75 percent under various recovery riders previously approved by the OCC; and (iv) recovery through OG&E's fuel adjustment clause of approximately $4.8 million annually of certain expenses that historically had been recovered through base rates. OG&E expects the impact of the rate increase on its customers and service territory to be minimal over the next 12 months as the rate increase will be more than offset by lower fuel costs attributable to prior fuel over recoveries from lower than forecasted fuel costs. On July 24, 2009, the OCC issued an order approving the settlement agreement. New electric rates were implemented August 3, 2009.

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2007

The OCC routinely audits activity in OG&E's fuel adjustment clause for each calendar year. In September 2008, the OCC Staff filed an application for a prudence review of OG&E's 2007 fuel adjustment clause. OG&E is required to provide minimum filing requirements ("MFR") within 60 days of the application; however, OG&E requested and was granted an extension to file the MFRs by January 16, 2009, on which date the MFRs were submitted by OG&E. A procedural schedule was established on April 24, 2009. On August 12, 2009, all parties to this case signed a settlement agreement in this matter, stating that OG&E's generation and fuel procurement processes and costs during the 2007 calendar year were prudent. A hearing on the settlement agreement was held on September 10, 2009 and the ALJ recommended approval of the settlement agreement. On October 15, 2009, the OCC issued an order adopting the findings in the settlement agreement.

Pending Regulatory Matters

OG&E OU Spirit Wind Power Project

OG&E signed contracts on July 31, 2008 for approximately 101 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the OU Spirit wind project in western Oklahoma ("OU Spirit"). As discussed below, OU Spirit is part of OG&E's goal to increase its wind power generation portfolio in the near future. On July 30, 2009, OG&E filed an application with the OCC requesting pre-approval to recover from Oklahoma customers the cost to construct OU Spirit at a cost of approximately $265.8 million. On August 14, 2009, OG&E filed its testimony in this matter. On October 15, 2009, all parties to this case signed a settlement agreement that would provide pre-approval of OU Spirit and authorize OG&E to begin recovering the costs of OU Spirit through a rider mechanism as the individual turbines are placed into service which is expected in November and December 2009. The settlement agreement also assigns to OG&E's customers the proceeds from the sale of OU Spirit renewable energy credits to the University of Oklahoma. The settlement agreement permits the recovery of up to $270 million of eligible construction costs, including recovery of the costs of the conservation project for the lesser prairie chicken as discussed below; however, OG&E may request approval of any cost in excess of $270 million in OG&E's next general rate case. The net impact on the average residential customer's 2010 electric bill is estimated to be approximately 90 cents per month, decreasing to 80 cents per month in 2011. OU Spirit is expected to be added to OG&E's regulated rate base as part of a general rate case in 2011, at which time the rider would cease. OG&E expects to receive an order from the OCC in this matter later in the fourth quarter of 2009. Capital expenditures associated with this project are expected to be approximately $270 million, of which approximately $36 million were incurred in 2008 and approximately $173 million were incurred from January 1, 2009 to September 30, 2009.

In connection with OU Spirit, in January 2008, OG&E filed with the SPP for a Large Generator Interconnection Agreement ("LGIA") 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 LGIA. On May 29, 2009, OG&E executed an interim LGIA, allowing OU Spirit to interconnect to the transmission grid, subject to certain conditions. In connection with the interim LGIA, OG&E posted a letter of credit with the SPP of approximately $10.9 million 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 LGIA with the FERC on June 29, 2009. On August 27, 2009, the FERC issued an order accepting the interim LGIA, subject to certain conditions, which enables OU Spirit to interconnect into the transmission grid until the final LGIA can be put in place, which is expected by mid-2010.

In connection with OU Spirit and to support the continued development of Oklahoma's wind resources, on April 1, 2009, OG&E announced a $3.75 million project with the Oklahoma Department of Wildlife Conservation to help provide a habitat for the lesser prairie chicken, which ranks as one of Oklahoma's more imperiled species. Through its efforts, OG&E hopes to help offset the effect of wind farm development on the lesser prairie chicken and help ensure that the bird does not reach endangered status, which would significantly limit the ability to develop Oklahoma's wind potential.

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 current 170 MWs to 770 MWs and, as part of this plan, on December 8, 2008, OG&E issued an RFP to wind developers for construction of up to 300 MWs of new capability. In June 2009, OG&E announced that it had selected a short list of bidders for a total of 430 MWs and that is was considering acquiring more than the approximately 300 MWs of wind energy originally contemplated in the initial RFP. On September 29, 2009, OG&E announced that, from its short list, it had reached agreements with two developers who will build two new wind farms, totaling 280 MWs, in northwestern Oklahoma. The construction of the new wind farms is contingent upon OCC approval of power-purchase agreements negotiated by OG&E. Under the terms of the agreements, CPV Keenan will build a 150 MW wind farm in Woodward County and Edison Mission Energy will build a 130 MW facility in Dewey County near Taloga. The agreements are both 20-year power-purchase agreements, under which the developers will build, own and operate the wind generating facilities and OG&E will purchase their electric output. OG&E expects to file separate applications in October 2009 with the OCC seeking pre-approval for the recovery of the costs associated with purchasing power from these projects. Negotiations with the third bidder on OG&E's short list announced in June, for an additional 150 MWs of wind energy from Texas County were terminated in early October. OG&E expects to solicit additional proposals from wind developers in the future with a goal of adding more wind generation in 2011 or 2012.

SPP Transmission/Substation Projects

In 2007, the SPP notified OG&E to construct approximately 44 miles of new 345 kilovolt (“kV”) transmission line which will originate at the existing OG&E 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 April 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.”

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 at a cost of approximately $211 million. This transmission line is a critical first step to increased wind development in western Oklahoma. In the application, OG&E also requested authorization to implement a recovery rider to be effective when the transmission line is completed and in service, which is expected during 2010. Finally, the application requested the OCC to approve new renewable tariff offerings to OG&E’s Oklahoma customers. A settlement agreement was signed by all parties in the matter on July 31, 2008. Under the terms of the settlement agreement, the parties agreed that the Company will: (i) receive pre-approval for construction of a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma and a conclusion that the construction costs of the transmission line are prudent, (ii) receive a recovery rider for the revenue requirement of the $218 million in construction costs and allowance for funds used during construction (“AFUDC”) when the transmission line is completed and in service until new rates are implemented in a subsequent rate case and (iii) to the extent the construction costs and AFUDC for the transmission line exceed $218 million OG&E be permitted to show that such additional costs are prudent and allowed to be recovered. On September 11, 2008, the OCC issued an order approving the settlement agreement. At September 30, 2009, the construction costs and AFUDC incurred were approximately $157 million. Separately, on July 29, 2008, the SPP Board of Directors approved the proposed transmission line discussed above. On February 2, 2009, OG&E received SPP approval to begin construction of the transmission line and the associated Woodward District Extra High Voltage substation. During the second quarter of 2009, OG&E received a favorable outcome in three local court cases challenging OG&E’s use of eminent domain to obtain rights-of-way. OG&E expects to have additional challenges to the transmission line in another county where rights-of-way are being purchased. 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 approximately 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, approximately 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 a set of 345 kV projects referred to as “Balanced Portfolio 3E”. Balanced Portfolio 3E includes four projects to be built by OG&E and includes: (i) construction of approximately 72 miles of transmission line from OG&E's Woodward District Extra High Voltage 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 approximately $105 million for OG&E, (ii) construction of approximately 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 approximately $131 million for OG&E, (iii) construction of approximately 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 approximately $41 million for OG&E 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 approximately $8 million for OG&E. All of the Balanced Portfolio 3E projects are expected to be in service by April 2014. 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. 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."

Conservation and Energy Efficiency Programs

On September 17, 2009, OG&E filed an application with the OCC seeking approval of a comprehensive Demand Program portfolio designed to promote energy efficiency and conservation for each class of OG&E customers. Eight programs are proposed, ranging from residential weatherization to commercial lighting. In seeking approval of the Demand Programs, OG&E also seeks recovery of the program and related costs through a rider that would be added to customers' electric bills. OG&E's request is expected to increase the average residential electric bill by less than $1.40 per month. A procedural schedule has not been established in this matter.

Tallgrass Joint Venture

In July 2008, the Tallgrass joint venture was formed to construct high-capacity transmission line projects in western Oklahoma. The Company owns 50 percent of Tallgrass. Tallgrass is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. The Tallgrass projects are subject to creation by the SPP of a cost allocation method that would spread the total cost across the SPP region. OGE Energy is uncertain as to the timing of when the cost allocation method will be developed and approved. OGE Energy filed an application with the FERC in October 2008 for cost recovery of these projects subject to SPP and FERC approval for these projects. On December 2, 2008, the FERC granted Tallgrass' request for transmission rate incentives for the initial projects, established a base ROE for initial projects, approved certain accounting treatments for the initial projects and set the formula rate and accompanying protocols for hearing and settlement discussions. Tallgrass' initial projects will include 765 kV lines from Woodward 120 miles northwest to Guymon in the Oklahoma Panhandle and from Woodward 50 miles north to the Kansas border. An SPP study estimates cost for the two projects to be approximately $500 million, of which OGE Energy's portion will be approximately $250 million. The capital expenditures related to the Tallgrass projects discussed above are excluded from 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." The SPP continues to review the initial Tallgrass projects and has not made a final determination whether these projects should be built. If the SPP determines that the above 765 kV projects should be 345 kV projects, these projects are expected to be completed by OG&E.

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

On July 20, 2009, the OCC Staff filed an application for a prudence review of OG&E's 2008 fuel adjustment clause. On September 18, 2009, the MFRs were submitted by OG&E. A procedural schedule has not been established in this matter.

Enogex FERC Section 311 2009 Rate Case

Effective April 1, 2009, Enogex began offering a firm Section 311 service in its East Zone. Offering this service required the filing of a new rate case at the FERC to establish rates for the firm service. Accordingly, 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 a revised Statement of Operating Conditions Applicable to Transportation Services ("SOC") with the FERC to describe the terms, conditions and operating arrangements for the new service.

The maximum rate for the new firm East Zone Section 311 transportation service was effective April 1, 2009. The revised zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for both the firm 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 has filed answers to the interventions and protests in both matters. On August 3, 2009, the FERC Staff served data requests on Enogex seeking additional information regarding various aspects of the filing. Enogex submitted responses to FERC Staff's data requests in August, September and October 2009. 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.

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 durations) 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.

North American Electric Reliability Corporation

The Energy Policy Act of 2005 gave the FERC authority to establish mandatory electric reliability rules enforceable with monetary penalties. The FERC approved the North American Electric Reliability Corporation ("NERC") as the Electric Reliability Organization for North America and delegated to it the development and enforcement of electric transmission reliability rules. In September 2009, OG&E completed a NERC Critical Infrastructure Protection ("CIP") spot check audit. Resolution of any audit findings is expected in 2010; however, OG&E does not expect the resolution of any audit findings to have a material impact on its operations. OG&E is subject to a NERC compliance audit every three years as well as periodic spot check audits. The next compliance audit is scheduled for 2011, which will incorporate both NERC CIP and non-CIP standards.

National Legislative Initiatives

In February 2009, the President signed into law the American Recovery and Reinvestment Act of 2009 ("ARRA"). 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. After review of the ARRA, 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 in Oklahoma. 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. Receipt of the grant monies is contingent upon successful negotiations with the DOE on final details of the award. OG&E is also expected to promptly seek approval from the OCC for matching fund recovery.

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. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located primarily 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.

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 ("Tallgrass") to construct high-capacity transmission line projects in western Oklahoma. The Company owns 50 percent of Tallgrass. Tallgrass is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. The Tallgrass projects are subject to creation by the Southwest Power Pool ("SPP") of a cost allocation method that would spread the total cost across the SPP region. OGE Energy is uncertain as to the timing of when the cost allocation method will be developed and approved. OGE Energy filed an application with the FERC in October 2008 for cost recovery of these projects subject to SPP and FERC approval for these projects. On December 2, 2008, the FERC granted Tallgrass' request for transmission rate incentives for the initial projects, established a base return on equity for initial projects, approved certain accounting treatments for the initial projects and set the formula rate and accompanying protocols for hearing and settlement discussions. Tallgrass' initial projects will 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. A SPP study estimates cost for the two projects to be approximately $500 million, of which OGE Energy's portion will be approximately $250 million.

Executive Overview

Financial Strategy

The Company's vision 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 2009 through 2012 include a compound annual earnings growth rate of five to seven percent on a weather-normalized basis as well as an annual dividend growth rate of two percent subject to approval by the 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 our shareholder base, our financial position, our growth targets, the composition of our assets and investment opportunities. The Company believes it can accomplish these financial goals 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, 2009 as Compared to Three Months Ended September 30, 2008

Net income attributable to OGE Energy was approximately $136.8 million, or $1.40 per diluted share, during the three months ended September 30, 2009, as compared to approximately $139.5 million, or $1.50 per diluted share, during the same period in 2008. The decrease in net income attributable to OGE Energy of approximately $2.7 million, or $0.10 per diluted share, during the three months ended September 30, 2009 as compared to the same period in 2008 was primarily due to:

net income at OG&E of approximately $123.2 million during the three months ended September 30, 2009 as compared to approximately $107.1 million during the same period in 2008, which was an increase in net income of approximately $16.1 million, or $0.11 per diluted share of the Company's common stock, during the three months ended September 30, 2009 as compared to the same period in 2008 primarily due to a higher gross margin on revenues ("gross margin") and higher other income partially offset by higher operation and maintenance expense, higher depreciation and amortization expense and higher income tax expense;

net income at Enogex of approximately $18.1 million during the three months ended September 30, 2009 as compared to approximately $28.3 million during the same period in 2008, which was a decrease in net income of approximately $10.2 million, or $0.12 per diluted share of the Company's common stock, during the three months ended September 30, 2009 as compared to the same period in 2008 primarily due to a lower gross margin, higher depreciation and amortization expense and higher interest expense partially offset by lower operation and maintenance expense and lower income tax expense;

net loss at OGE Energy of approximately $0.8 million during the three months ended September 30, 2009 as compared to net income of approximately $0.1 million during the same period in 2008, which was an increase in the net loss of approximately $0.9 million, or $0.01 per diluted share of the Company's common stock, during the three months ended September 30, 2009 as compared to the same period in 2008; and

net loss at OGE Energy's natural gas marketing subsidiary, OGE Energy Resources, Inc. ("OERI"), of approximately $3.7 million during the three months ended September 30, 2009 as compared to net income of approximately $4.0 million during the same period in 2008, which was an increase in the net loss of approximately $7.7 million, or $0.08 per diluted share of the Company's common stock, during the three months ended September 30, 2009 as compared to the same period in 2008 primarily due to a lower gross margin partially offset by an income tax benefit during the three months ended September 30, 2009 as compared to income tax expense during the same period in 2008.

The Company's earnings per share were also adversely affected by an increase in the diluted average common shares outstanding.

Timing Items. OERI's net loss for the three months ended September 30, 2009 was approximately $3.7 million, which included a net loss of approximately $0.4 million resulting from recording hedges of natural gas inventory held in storage at market value on September 30, 2009. The offsetting gains from the sale of storage inventory are expected to be realized during the fourth quarter of 2009 and first quarter of 2010.

OERI's net income for the three months ended September 30, 2008 was approximately $4.0 million, which included a net loss of approximately $0.9 million resulting from recording hedges associated with various transportation contracts at market value on September 30, 2008. The offsetting gains from physical utilization of the transportation capacity and from the sale of storage inventory were realized during the remainder of 2008.

Nine Months Ended September 30, 2009 as Compared to Nine Months Ended September 30, 2008

Net income attributable to OGE Energy was approximately $224.1 million, or $2.31 per diluted share, during the nine months ended September 30, 2009, as compared to approximately $209.6 million, or $2.26 per diluted share, during the same period in 2008. The increase in net income attributable to OGE Energy of approximately $14.5 million, or $0.05 per diluted share, during the nine months ended September 30, 2009 as compared to the same period in 2008 was primarily due to:

net income at OG&E of approximately $180.9 million during the nine months ended September 30, 2009 as compared to approximately $126.7 million during the same period in 2008, which was an increase in net income of approximately $54.2 million, or $0.50 per diluted share of the Company's common stock, during the nine months ended September 30, 2009 as compared to the same period in 2008 primarily due to a higher gross margin, higher other income and lower operation and maintenance expense partially offset by higher depreciation and amortization expense, higher interest expense and higher income tax expense;

net income at Enogex of approximately $49.5 million during the nine months ended September 30, 2009 as compared to approximately $81.7 million during the same period in 2008, which was a decrease in net income of approximately $32.2 million, or $0.37 per diluted share of the Company's common stock, during the nine months ended September 30, 2009 as compared to the same period in 2008 primarily due to a lower gross margin and higher depreciation and amortization expense partially offset by lower operation and maintenance expense and lower income tax expense;

net loss at OGE Energy of approximately $2.2 million during the nine months ended September 30, 2009 as compared to approximately $0.1 million during the same period in 2008, which was an increase in the net loss of approximately $2.1 million, or $0.02 per diluted share of the Company's common stock, during the nine months ended September 30, 2009 as compared to the same period in 2008 primarily due to life insurance proceeds from one of the Company's directors received in 2008; and

net loss at OERI of approximately $4.1 million during the nine months ended September 30, 2009 as compared to net income of approximately $1.3 million during the same period in 2008, which was a decrease in the net loss of approximately $5.4 million, or $0.06 per diluted share of the Company's common stock, during the nine months ended September 30, 2009 as compared to the same period in 2008 primarily due to a lower gross margin partially offset by an income tax benefit during the nine months ended September 30, 2009 as compared to income tax expense during the same period in 2008.

The Company's earnings per share were also adversely affected by an increase in the diluted average common shares outstanding.

Timing Items. OERI's net loss for the nine months ended September 30, 2009 was approximately $4.2 million, which included a net loss of approximately $0.3 million resulting from recording hedges of natural gas inventory held in storage at market value in September 30, 2009. The offsetting gains from physical utilization of the transportation capacity and from the sale of storage inventory are expected to be realized during the fourth quarter of 2009 and first quarter of 2010.

OERI's net income for the nine months ended September 30, 2008 was approximately $1.3 million, which included a net loss of approximately $1.7 million resulting from recording hedges associated with various transportation contracts at market value on September 30, 2008. The offsetting gains from physical utilization of the transportation capacity and from the sale of storage inventory were realized during the remainder of 2008.

Recent Developments and Regulatory Matters

Changes in the Capital and Commodity Markets

The volatility in global capital markets experienced in late 2008 and early 2009 led to a reduction in the value of long-term investments held in OGE Energy's pension trust and postretirement benefit plan trusts. However, more recently in 2009, the market values have partially recovered from the decline in value experienced in late 2008 and early 2009. OGE Energy could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

Enogex's gathering and processing margins generally improve when natural gas liquids ("NGL") prices are high relative to the price of natural gas (sometimes referred to as high commodity spreads). For much of the first nine months of 2008, commodity spreads were relatively high. However, later in 2008, commodity spreads were significantly lower. During the first nine months of 2009, commodity spreads have increased over year-end 2008 levels but still remain significantly lower than commodity spreads in early to mid-2008. As a result of the lower commodity spread environment, Enogex's results for 2009 will be affected. See 2009 Outlook below. Also, prices of natural gas and NGLs have been extremely volatile, and Enogex expects this volatility to continue.

OG&E OU Spirit Wind Power Project

OG&E signed contracts on July 31, 2008 for approximately 101 megawatts ("MW") of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the OU Spirit wind project in western Oklahoma ("OU Spirit"). As discussed below, OU Spirit is part of OG&E's goal to increase its wind power generation portfolio in the near future. On July 30, 2009, OG&E filed an application with the OCC requesting pre-approval to recover from Oklahoma customers the cost to construct OU Spirit at a cost of approximately $265.8 million. On August 14, 2009, OG&E filed its testimony in this matter. On October 15, 2009, all parties to this case signed a settlement agreement that would provide pre-approval of OU Spirit and authorize OG&E to begin recovering the costs of OU Spirit through a rider mechanism as the individual turbines are placed into service which is expected in November and December 2009. The settlement agreement also assigns to OG&E's customers the proceeds from the sale of OU Spirit renewable energy credits to the University of Oklahoma. The settlement agreement permits the recovery of up to $270 million of eligible construction costs, including recovery of the costs of the conservation project for the lesser prairie chicken as discussed below; however, OG&E may request approval of any cost in excess of $270 million in OG&E's next general rate case. The net impact on the average residential customer's 2010 electric bill is estimated to be approximately 90 cents per month, decreasing to 80 cents per month in 2011. OU Spirit is expected to be added to OG&E's regulated rate base as part of a general rate case in 2011, at which time the rider would cease. OG&E expects to receive an order from the OCC in this matter later in the fourth quarter of 2009. Capital expenditures associated with this project are expected to be approximately

$270 million, of which approximately $36 million were incurred in 2008 and approximately $173 million were incurred from January 1, 2009 to September 30, 2009.

In connection with OU Spirit, in January 2008, OG&E filed with the SPP for a Large Generator Interconnection Agreement ("LGIA") 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 LGIA. On May 29, 2009, OG&E executed an interim LGIA, allowing OU Spirit to interconnect into the transmission grid, subject to certain conditions. In connection with the interim LGIA, OG&E posted a letter of credit with the SPP of approximately $10.9 million 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 LGIA with the FERC on June 29, 2009. On August 27, 2009, the FERC issued an order accepting the interim LGIA, subject to certain conditions, which enables OU Spirit to interconnect into the transmission grid until the final LGIA can be put in place, which is expected by mid-2010.

In connection with OU Spirit and to support the continued development of Oklahoma's wind resources, on April 1, 2009, OG&E announced a $3.75 million project with the Oklahoma Department of Wildlife Conservation to help provide a habitat for the lesser prairie chicken, which ranks as one of Oklahoma's more imperiled species. Through its efforts, OG&E hopes to help offset the effect of wind farm development on the lesser prairie chicken and help ensure that the bird does not reach endangered status, which would significantly limit the ability to develop Oklahoma's wind potential.

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 current 170 MWs 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 June 2009, OG&E announced that it had selected a short list of bidders for a total of 430 MWs and that is was considering acquiring more than the approximately 300 MWs of wind energy originally contemplated in the initial RFP. On September 29, 2009, OG&E announced that, from its short list, it had reached agreements with two developers who will build two new wind farms, totaling 280 MWs, in northwestern Oklahoma. The construction of the new wind farms is contingent upon OCC approval of power-purchase agreements negotiated by OG&E. Under the terms of the agreements, CPV Keenan will build a 150 MW wind farm in Woodward County and Edison Mission Energy will build a 130 MW facility in Dewey County near Taloga. The agreements are both 20-year power-purchase agreements, under which the developers will build, own and operate the wind generating facilities and OG&E will purchase their electric output. OG&E expects to file separate applications in October 2009 with the OCC seeking pre-approval for the recovery of the costs associated with purchasing power from these projects. Negotiations with the third bidder on OG&E's short list announced in June, for an additional 150 MW of wind energy from Texas County were terminated in early October. OG&E expects to solicit additional proposals from wind developers in the future with a goal of adding more wind generation in 2011 or 2012.

Agreement with Midcontinent Express Pipeline, LLC

In December 2006, Enogex entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC ("MEP") for a primary term of ten years (subject to possible extension) that would give MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP lease agreement is currently 272 million cubic feet per day ("MMcf/d"), with the quantity ultimately to be leased subject to being increased by mutual agreement pursuant to the lease agreement. In addition to MEP's lease of Enogex's capacity, the MEP project included construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Enogex's capital expenditures related to this project were approximately $99 million.

On July 25, 2008, the FERC issued its order approving the MEP project including the approval of a limited jurisdiction certificate authorizing the Enogex lease agreement to MEP. Further, the FERC order rejected 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, one protestor filed a request for rehearing. The FERC denied the request for rehearing, and Enogex commenced service to MEP under the lease agreement on June 1, 2009. On July 16, 2009, the protestor filed a petition for review of the FERC's orders before the United States Court of Appeals for the District of Columbia Circuit requesting that the orders be modified or set aside on the grounds that they are arbitrary, capricious and contrary to law. The petitioner, the FERC and interested parties that have sought intervenor status will be given an opportunity to brief the issues. Enogex has filed its intervention and expects to participate in the filing of a joint intervenors' brief in support of the FERC's order in this matter. On October 27, 2009, the Court of Appeals issued an order establishing the briefing schedule for the proceeding which provides for the briefing to be completed in the first quarter of 2010.

Enogex FERC Section 311 2009 Rate Case

Effective April 1, 2009, Enogex began offering a firm Section 311 service in its East Zone. Offering this service required the filing of a new rate case at the FERC to establish rates for the firm service. Accordingly, 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 a revised Statement of Operating Conditions Applicable to Transportation Services ("SOC") with the FERC to describe the terms, conditions and operating arrangements for the new service.

The maximum rate for the new firm East Zone Section 311 transportation service was effective April 1, 2009. The revised zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for both the firm 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 has filed answers to the interventions and protests in both matters. On August 3, 2009, the FERC Staff served data requests on Enogex seeking additional information regarding various aspects of the filing. Enogex submitted responses to FERC Staff's data requests in August, September and October 2009. 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.

Gathering and Processing System Expansions

Texas Panhandle / West Side Expansions

In August 2009, Enogex added another 8,000 horsepower of low pressure compression in Wheeler County, Texas. The capital expenditures associated with the additional horsepower of low pressure compression were approximately $17 million.

Enogex is constructing a new 120 MMcf/d cryogenic plant equipped with electric compression near Clinton, Oklahoma. This plant will process new gas developing in the area and is expected to be in service in early November 2009. In support of this plant, Enogex has installed approximately 15 miles of gathering pipe, 2.5 miles of transmission pipe, 10,000 horsepower of inlet compression, as well as other system upgrades. The capital expenditures associated with these projects are expected to be approximately $76 million.

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, are expected to be in service in late 2010. The capital expenditures for this initial stage of the construction are expected to be approximately $13 million.

Southeastern Oklahoma / East Side Expansions

Enogex plans to construct a new compressor station in Coal County, Oklahoma, as well as approximately 10 miles of gathering pipe and related treating facilities. The station would be designed to accommodate up to 6,700 horsepower of low pressure compression and would be supported by approximately five miles of 20-inch steel pipe and five miles of 12-inch steel pipe. The new compressor station would also include the lease of associated gas treating facilities for the incremental gas in this area. The initial 2,700 horsepower at the compressor station, and the gathering pipe, are expected to be in service in February 2010. The capital expenditures for this initial stage of the construction are expected to be approximately $12 million.

Enogex Additional Processing Capacity

Enogex has placed an order for a cryogenic processing plant that is scheduled for delivery in mid-November 2009, which, when installed, would be expected to add another 120 MMcf/d of processing capacity to Enogex's system. The capital expenditures associated with the purchase of the new processing cryogenic plant are expected to be approximately $16 million and excludes any expenditures for installation and ancillary equipment.

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 May 2010. The capital expenditures associated with these projects are expected to be approximately $25 million.

2009 Outlook

The Company's 2009 earnings guidance remains unchanged at $2.30 to $2.60 per average diluted share. The Company currently projects 2009 earnings to be towards the middle of the range. See "2009 Outlook" in the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 for a description of the key factors and assumptions underlying this guidance.

2010 Outlook

The Company's 2010 earnings guidance is between approximately $265 million and $290 million of net income, or $2.70 to $2.95 per average diluted share.

Key factors and assumptions for 2010 include:

Consolidated OGE Energy

- Between 98 million and 99 million average diluted shares outstanding;
- An effective tax rate of approximately 29 percent; and
- A projected loss at the holding company between $7 million and $9 million, or $0.07 to $0.09 per diluted share, primarily due to interest expense relating to long and short-term debt borrowings and an anticipated loss at OERI primarily due to a transportation contract agreement.

OG&E

The Company projects OG&E to earn approximately $207 million to $217 million, or $2.10 to $2.20 per average diluted share, in 2010. The key factors and assumptions include:

- Normal weather patterns are experienced for the year;
- Gross margin on revenues of approximately $1.05 billion to $1.06 billion. The key assumptions for gross margin are listed below:
  - Sales growth of approximately 0.9 percent on a weather adjusted basis;
  - OU Spirit is approved by the OCC and the rider is effective January 1, 2010; and
  - The Oklahoma City, Oklahoma to Woodward, Oklahoma transmission line, otherwise known as Windspeed, is in service with the rider effective April 1, 2010;
- Operating expenses of approximately $655 million to $665 million, with operation and maintenance expenses comprising approximately 60 percent of total;
- Interest expense of approximately $105 million to $115 million, which assumes approximately $250 million of additional long-term debt issued by OG&E in mid-2010;

Allowance for equity funds used during construction ("AEFUDC") income of approximately $5 million; and
An effective tax rate of approximately 27 percent.

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.

Enogex

The Company projects Enogex to earn approximately $63 million to $85 million, or $0.64 to $0.86 per average diluted share, in 2010. The key factors and assumptions include:

Total Enogex anticipated gross margin of approximately $370 million to $400 million. The gross margin assumption includes:

Transportation and storage gross margin contribution of approximately $150 million to $160 million, of which approximately 20 percent is attributable to the storage business;

Gathering and processing gross margin contribution of approximately $220 million to $240 million, with equal contributions to gross margin from each business;

Key factors affecting the gathering and processing gross margin forecast are:

Assumed increase of five to seven percent in gathered volumes over 2009;

At the midpoint of Enogex’s gathering and processing assumption Enogex has included:

Realized commodity spreads of $5.15 per Million British thermal unit (“MMBtu”) in 2010. The realized commodity spread takes into account that 76 percent of non-ethane processing volumes that bear price risk are hedged and the amortized cost of the hedges is included in the realized commodity spread calculation and that ethane is in rejection for all of 2010. Every 10 percent change in commodity spreads from $5.15 per MMBtu changes net income by approximately $4.0 million on an annual basis assuming all other margins remain static;

Natural gas price of $5.85 per MMBtu in 2010;

Realized weighted average NGLs price of $1.08 per gallon in 2010; and

Realized condensate spread of $8.42 per MMBtu in 2010;

Operating expenses of approximately $220 million to $230 million, with operation and maintenance expenses comprising approximately 60 percent of total;

Interest expense of approximately $30 million to $35 million; and

An effective tax rate of approximately 39 percent.

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 net income at the midpoint of Enogex’s assumptions.

Reconciliation of projected EBITDA to projected net income

| (In millions) | Twelve Months Ended December 31, 2010 (A) |
|---|---|
| Net Income Attributable to Enogex LLC | $ 74.0 |
| Add: | |
| Interest expense, net | 33.0 |
| Income tax expense | 49.0 |
| Depreciation and amortization | 69.0 |
| EBITDA | $ 225.0 |

(A) Based on midpoint of 2010 guidance.

For a discussion of the reasons for the use of EBITDA, as well as the limitations of EBITDA as an analytical tool, see “Enogex’s Non-GAAP Financial Measure” 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, 2009 as compared to the same period in 2008 and the Company’s consolidated financial position at September 30, 2009. Due to seasonal fluctuations and other factors, the operating results for the three and nine months ended September 30, 2009 are not necessarily indicative of the results that may be expected for the year ending December 31, 2009 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) | 2009 | 2008 | 2009 | 2008 |
| Operating income | $ 229.7 | $ 231.2 | $ 408.1 | $ 402.0 |
| Net income attributable to OGE Energy | $ 136.8 | $ 139.5 | $224.1 | $209.6 |
| Basic average common shares outstanding | 96.7 | 92.6 | 96.0 | 92.2 |
| Diluted average common shares outstanding | 97.7 | 93.0 | 96.9 | 92.7 |
| Basic earnings per average common share attributable to OGE Energy common shareholders | $ 1.42 | $ 1.51 | $ 2.34 | $ 2.27 |
| Diluted earnings per average common share attributable to OGE Energy common shareholders | $ 1.40 | $ 1.50 | $ 2.31 | $ 2.26 |
| Dividends declared per share | $ 0.3550 | $ 0.3475 | $1.0650 | $1.0425 |

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) | 2009 | 2008 | 2009 | 2008 |
| OG&E (Electric Utility) | $ 193.2 | $ 169.6 | $ 308.5 | $ 239.6 |
| Enogex (Natural Gas Pipeline) | | | | |
| Transportation and storage | 26.0 | 26.2 | 71.2 | 55.3 |
| Gathering and processing | 15.9 | 29.4 | 35.1 | 105.5 |
| OERI (Natural Gas Marketing) | (5.8) | 6.5 | (6.3) | 1.6 |
| Other Operations (A) | 0.4 | (0.5) | (0.4) | --- |
| Consolidated operating income | $ 229.7 | $ 231.2 | $ 408.1 | $ 402.0 |

(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) | 2009 | 2008 | 2009 | 2008 |
| Operating revenues | $ 577.9 | $ 682.5 | $ 1,339.9 | $ 1,589.6 |
| Cost of goods sold | 235.7 | 380.9 | 595.0 | 934.2 |
| Gross margin on revenues | 342.2 | 301.6 | 744.9 | 655.4 |
| Other operation and maintenance | 85.7 | 79.9 | 248.9 | 260.0 |
| Depreciation and amortization | 47.3 | 37.7 | 138.8 | 110.9 |
| Impairment of assets | --- | --- | 0.3 | --- |
| Taxes other than income | 16.0 | 14.4 | 48.4 | 44.9 |
| Operating income | 193.2 | 169.6 | 308.5 | 239.6 |
| Interest income | 0.2 | 1.7 | 1.0 | 2.7 |
| Allowance for equity funds used during construction | 5.5 | --- | 10.7 | --- |
| Other income (loss) | 5.9 | (1.1) | 14.7 | 0.7 |
| Other expense | 1.3 | 0.6 | 2.5 | 11.5 |
| Interest expense | 22.8 | 18.7 | 70.3 | 55.2 |
| Income tax expense | 57.5 | 43.8 | 81.2 | 49.6 |
| Net income | $ 123.2 | $ 107.1 | $ 180.9 | $ 126.7 |
| Operating revenues by classification | | | | |
| Residential | $ 253.4 | $ 285.4 | $ 557.3 | $ 617.1 |
| Commercial | 144.4 | 169.0 | 336.1 | 385.0 |
| Industrial | 52.5 | 71.9 | 128.3 | 178.4 |
| Oilfield | 38.4 | 47.6 | 100.5 | 120.3 |
| Public authorities and street light | 54.0 | 66.0 | 126.8 | 153.7 |
| Sales for resale | 15.3 | 20.3 | 40.0 | 52.1 |
| Provision for rate refund | --- | (0.2) | (0.6) | (0.2) |
| System sales revenues | 558.0 | 660.0 | 1,288.4 | 1,506.4 |
| Off-system sales revenues | 11.1 | 13.5 | 25.6 | 59.0 |
| Other | 8.8 | 9.0 | 25.9 | 24.2 |
| Total operating revenues | $ 577.9 | $ 682.5 | $ 1,339.9 | $ 1,589.6 |
| MWH (A) sales by classification (in millions) | | | | |
| Residential | 2.7 | 2.8 | 6.8 | 7.0 |
| Commercial | 1.8 | 1.8 | 4.9 | 4.9 |
| Industrial | 1.0 | 1.1 | 2.7 | 3.1 |
| Oilfield | 0.8 | 0.8 | 2.2 | 2.2 |
| Public authorities and street light | 0.8 | 0.9 | 2.2 | 2.3 |
| Sales for resale | 0.4 | 0.4 | 1.0 | 1.1 |
| System sales | 7.5 | 7.8 | 19.8 | 20.6 |
| Off-system sales | 0.3 | 0.3 | 0.8 | 1.0 |
| Total sales | 7.8 | 8.1 | 20.6 | 21.6 |
| Number of customers | 775,863 | 768,857 | 775,863 | 768,857 |
| Average cost of energy per KWH (B) – cents | | | | |
| Natural gas | 3.468 | 9.962 | 3.497 | 9.362 |
| Coal | 1.886 | 1.181 | 1.737 | 1.144 |
| Total fuel | 2.575 | 4.033 | 2.394 | 3.648 |
| Total fuel and purchased power | 2.803 | 4.410 | 2.677 | 4.038 |
| Degree days (C) | | | | |

| | | | | |
|---|---|---|---|---|
| Heating - Actual | 17 | 2 | 1,946 | 2,036 |
| Heating - Normal | 29 | 29 | 2,228 | 2,247 |
| Cooling - Actual | 1,189 | 1,290 | 1,849 | 2,023 |
| Cooling - Normal | 1,295 | 1,295 | 1,850 | 1,851 |

(A) Megawatt-hour.

(B) Kilowatt-hour.

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

Three Months Ended September 30, 2009 as Compared to Three Months Ended September 30, 2008

Operating Income

OG&E's operating income increased approximately $23.6 million during the three months ended September 30, 2009 as compared to the same period in 2008 primarily due to a higher gross margin partially offset by higher operation and maintenance expense, higher depreciation and amortization expense and higher taxes other than income.

Gross Margin

Gross margin was approximately $342.2 million during the three months ended September 30, 2009 as compared to approximately $301.6 million during the same period in 2008, an increase of approximately $40.6 million, or 13.5 percent. The gross margin increased primarily due to:

- increased price variance, which included revenues related to the recovery through rates of the acquisition and operating costs of the 1,230 MW natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma ("Redbud Facility"), new revenues from the storm cost recovery rider, new revenues from the system hardening rider and higher revenues from the sales and customer mix, which increased the gross margin by approximately $28.7 million;
- new revenues from the $48.3 million Oklahoma rate increase in which the majority of the annual increase is recovered during the summer months, which increased the gross margin by approximately $21.1 million;
- new revenues from the Arkansas rate increase, which increased the gross margin by approximately $5.3 million; and
- new customer growth in OG&E's service territory, which increased the gross margin by approximately $2.8 million.

These increases in the gross margin were partially offset by:

- milder weather in OG&E's service territory, resulting in an approximate 7.8 percent decrease in cooling degree days in the third quarter of 2009 as compared to the same period in 2008, which decreased the gross margin by approximately $11.2 million; and
- lower demand and related revenues by non-residential customers in OG&E's service territory, which decreased the gross margin by approximately $6.7 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was approximately $189.5 million during the three months ended September 30, 2009 as compared to approximately $283.4 million during the same period in 2008, a decrease of approximately $93.9 million, or 33.1 percent, primarily due to lower natural gas prices. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. Purchased power costs were approximately $45.8 million during the three months ended September 30, 2009 as compared to approximately $97.5 million during the same period in 2008, a decrease of approximately $51.7 million, or 53.0 percent, primarily due to the termination of the purchase power agreement with the Redbud Facility following OG&E's purchase of the Redbud Facility in September 2008 as well as a decrease in purchases in the energy imbalance service market.

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 approximately $85.7 million during the three months ended September 30, 2009 as compared to approximately $79.9 million during the same period in 2008, an increase of approximately $5.8 million, or 7.3 percent. The increase in other operation and maintenance expenses was primarily due to:

- an increase of approximately $2.9 million in salaries and wages expense primarily due to salary increases in 2009;

- an increase of approximately $2.6 million due to increased spending on vegetation management;
- an increase of approximately $1.7 million in pension expense in 2009;
- an increase of approximately $1.2 million in professional services primarily due to the reclassification in 2008, from other operation and maintenance expense to capital costs, of legal expenses related to the acquisition of the Redbud Facility; and
- an increase of approximately $1.0 million primarily due to OG&E's demand-side management initiatives, which expenses are being recovered through a rider.

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

- a decrease of approximately $1.3 million in technical and construction services primarily due to the utilization of employees instead of contracting external labor for miscellaneous projects;
- a decrease of approximately $1.3 million due to lower bad debt expense primarily due to a change in the provision calculation as a result of the Oklahoma rate case whereby the portion of the uncollectible provision related to fuel will be recovered through the fuel adjustment clause beginning in August 2009 and going forward; and
- a decrease of approximately $1.2 million in fleet transportation expense primarily due to lower fuel costs in 2009.

Depreciation and amortization expense was approximately $47.3 million during the three months ended September 30, 2009 as compared to approximately $37.7 million during the same period in 2008, an increase of approximately $9.6 million, or 25.5 percent, primarily due to additional assets being placed into service, including the Redbud Facility that was placed into service in September 2008, and amortization of several regulatory assets.

Taxes other than income were approximately $16.0 million during the three months ended September 30, 2009 as compared to approximately $14.4 million during the same period in 2008, an increase of approximately $1.6 million, or 11.1 percent, primarily due to an increase in ad valorem taxes.

Additional Information

Interest Income. Interest income was approximately $0.2 million during the three months ended September 30, 2009 as compared to approximately $1.7 million during the same period in 2008, a decrease of approximately $1.5 million, or 88.2 percent, primarily due to interest from customers related to the fuel under recovery balance during the three months ended September 30, 2008.

Allowance for Equity Funds Used During Construction. AEFUDC was approximately $5.5 million during the three months ended September 30, 2009. There was no AEFUDC during the same period in 2008. The increase in AEFUDC was primarily due to construction costs associated with OU Spirit and the extra high voltage transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma being constructed by OG&E.

Other Income (Loss). Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating income. Other income was approximately $5.9 million during the three months ended September 30, 2009 as compared to a loss of approximately $1.1 million during the same period in 2008, an increase in other income of approximately $7.0 million. Approximately $3.6 million of the increase in other income related to the benefit associated with the tax gross-up of AEFUDC and approximately $2.7 million of the increase in other income was due to more customers participating in the guaranteed flat bill program and lower than expected usage resulting from milder weather during the third quarter of 2009 as compared to the same period in 2008.

Interest Expense. Interest expense was approximately $22.8 million during the three months ended September 30, 2009 as compared to approximately $18.7 million during the same period in 2008, an increase of approximately $4.1 million, or 21.9 percent. The increase in interest expense was primarily due to an increase of approximately $7.4 million in interest expense related to the issuances of long-term debt during the third and fourth quarters of 2008. This increase in interest expense was partially offset by:

a decrease of approximately $2.2 million related to interest on short-term debt primarily due to lower short-term borrowings in 2009 due to the issuance of long-term debt by OG&E during the third and fourth quarters of 2008; and a decrease of approximately $2.1 million primarily due to a higher allowance for borrowed funds used during construction for capitalized interest.

Income Tax Expense. Income tax expense was approximately $57.5 million during the three months ended September 30, 2009 as compared to approximately $43.8 million during the same period in 2008, an increase of approximately $13.7 million, or 31.3 percent, primarily due to higher pre-tax income in the third quarter of 2009 as compared to the same period in 2008 partially offset by an increase in Federal renewable energy credits and Oklahoma investment tax credits in the third quarter of 2009 as compared to the same period in 2008.

Nine Months Ended September 30, 2009 as Compared to Nine Months Ended September 30, 2008

Operating Income

OG&E's operating income increased approximately $68.9 million during the nine months ended September 30, 2009 as compared to the same period in 2008 primarily due to a higher gross margin and lower operation and maintenance expense partially offset by higher depreciation and amortization expense and higher taxes other than income.

Gross Margin

Gross margin was approximately $744.9 million during the nine months ended September 30, 2009 as compared to approximately $655.4 million during the same period in 2008, an increase of approximately $89.5 million, or 13.7 percent. The gross margin increased primarily due to:

- increased price variance, which included revenues related to the recovery through rates of the acquisition and operating costs of the Redbud Facility, new revenues from the storm cost recovery rider, new revenues from the system hardening rider and higher revenues from the sales and customer mix, which increased the gross margin by approximately $76.8 million;
- new revenues from the $48.3 million Oklahoma rate increase in which the majority of the annual increase is recovered during the summer months, which increased the gross margin by approximately $21.1 million;
- new revenues from the Arkansas rate increase, which increased the gross margin by approximately $6.4 million;
- new customer growth in OG&E's service territory, which increased the gross margin by approximately $6.2 million; and
- increased transmission revenues due to higher transmission volumes and increased rates due to the FERC formula rate tariff filing, which increased the gross margin by approximately $1.2 million.

These increases in gross margin were partially offset by:

- milder weather in OG&E's service territory, which decreased the gross margin by approximately $12.9 million; and
- lower demand and related revenues by non-residential customers in OG&E's service territory, which decreased the gross margin by approximately $8.9 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was approximately $467.7 million during the nine months ended September 30, 2009 as compared to approximately $719.6 million during the same period in 2008, a decrease of approximately $251.9 million, or 35.0 percent, primarily due to lower natural gas prices. Purchased power costs were approximately $125.8 million during the nine months ended September 30, 2009 as compared to approximately $214.1 million during the same period in 2008, a decrease of approximately $88.3 million, or 41.2 percent, primarily due to the termination of the purchase power agreement with the Redbud Facility following OG&E's purchase of the Redbud Facility in

September 2008 as well as a decrease in purchases in the energy imbalance service market.

Operating Expenses

Other operation and maintenance expenses were approximately $248.9 million during the nine months ended September 30, 2009 as compared to approximately $260.0 million during the same period in 2008, a decrease of approximately $11.1 million, or 4.3 percent. The decrease in other operation and maintenance expenses was primarily due to:

a decrease of approximately $9.5 million due to a correction of the over-capitalization of certain payroll, benefits, other employee related costs and overhead costs in previous years in March 2008, as discussed in Note 11 of Notes to Condensed Consolidated Financial Statements;
a decrease of approximately $8.4 million in contract technical and construction services attributable to decreased spending on overhauls at some of OG&E's power plants during the first nine months of 2009 as compared to the same period in 2008 and utilization of employees instead of contracting external labor;
a decrease of approximately $3.2 million due to the reclassification of 2006 and 2007 pension settlement costs to a regulatory asset due to the Arkansas rate case settlement, as discussed in Note 1 of Notes to Condensed Consolidated Financial Statements;
an increase in capitalized labor in the first nine months of 2009 as compared to the same period in 2008, which decreased other operation and maintenance expenses by approximately $3.2 million; and
a decrease of approximately $3.0 million in fleet transportation expense primarily due to lower fuel costs in 2009.

These decreases in other operation and maintenance expenses were partially offset by:

an increase of approximately $6.8 million in salaries and wages expense primarily due to salary increases in 2009;
an increase of approximately $3.9 million due to increased spending on vegetation management;
an increase of approximately $3.0 million due to OG&E's demand-side management initiatives, which expenses are being recovered through a rider;
an increase of approximately $2.1 million in medical and dental expenses; and
an increase of approximately $1.1 million due to increased bad debt expense primarily related to higher customer billings coupled with a higher charge-off rate partially offset by a decrease due to a change in the provision calculation as a result of the Oklahoma rate case whereby the portion of the uncollectible provision related to fuel will be recovered through the fuel adjustment clause beginning in August 2009 and going forward.

Depreciation and amortization expense was approximately $138.8 million during the nine months ended September 30, 2009 as compared to approximately $110.9 million during the same period in 2008, an increase of approximately $27.9 million, or 25.2 percent, primarily due to additional assets being placed into service, including the Redbud Facility that was placed into service in September 2008, and amortization of several regulatory assets.

Taxes other than income was approximately $48.4 million during the nine months ended September 30, 2009 as compared to approximately $44.9 million during the same period in 2008, an increase of approximately $3.5 million, or 7.8 percent, primarily due to an increase in ad valorem taxes.

Additional Information

Interest Income. Interest income was approximately $1.0 million during the nine months ended September 30, 2009 as compared to approximately $2.7 million during the same period in 2008, a decrease of approximately $1.7 million, or 63.0 percent, primarily due to interest from customers related to the fuel under recovery balance during the three months ended September 30, 2008.

Allowance for Equity Funds Used During Construction. AEFUDC was approximately $10.7 million during the nine months ended September 30, 2009. There was no AEFUDC during the same period in 2008. The increase in AEFUDC was primarily due to construction costs associated with OU Spirit and the extra high voltage transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma being constructed by OG&E.

Other Income. Other income was approximately $14.7 million during the nine months ended September 30, 2009 as compared to approximately $0.7 million during the same period in 2008, an increase of approximately $14.0

million. Approximately $6.9 million of the increase in other income related to the benefit associated with the tax gross-up of AEFUDC and approximately $6.4 million of the increase in other income was due to more customers participating in the guaranteed flat bill program and lower than expected usage resulting from milder weather during the first nine months of 2009 as compared to the same period in 2008.

Other Expense. Other expense was approximately $2.5 million during the nine months ended September 30, 2009 as compared to approximately $11.5 million during the same period of 2008, a decrease of approximately $9.0 million, or

78.3 percent, primarily due to 2008 write-downs of approximately $7.7 million for deferred costs associated with the cancelled Red Rock power plant and approximately $1.5 million associated with the 2007 and 2006 storm costs.

Interest Expense. Interest expense was approximately $70.3 million during the nine months ended September 30, 2009 as compared to approximately $55.2 million during the same period in 2008, an increase of approximately $15.1 million, or 27.4 percent. The increase in interest expense was primarily due to an increase of approximately $25.8 million in interest expense related to the issuances of long-term debt during the third and fourth quarters of 2008. This increase in interest expense was partially offset by:

- a decrease of approximately $5.4 million related to interest on short-term debt primarily due to lower short-term borrowings in 2009 due to the issuance of long-term debt by OG&E during the third and fourth quarters of 2008;
- a decrease of approximately $3.5 million due to a higher allowance for borrowed funds used during construction for capitalized interest; and
- a decrease of approximately $2.4 million due to the settlement of treasury lock agreements OG&E entered into related to the issuance of long-term debt by OG&E in January 2008.

Income Tax Expense. Income tax expense was approximately $81.2 million during the nine months ended September 30, 2009 as compared to approximately $49.6 million during the same period in 2008, an increase of approximately $31.6 million, or 63.7 percent, primarily due to higher pre-tax income in the first nine months of 2009 as compared to the same period in 2008 partially offset by an increase in Federal renewable energy credits and Oklahoma investment tax credits in the third quarter of 2009 as compared to the same period in 2008.

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

| Three Months Ended September 30, 2009 (In millions) | Transportation and Storage | Gathering and 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 | 11.3 | --- | 16.5 |
| Impairment of assets | --- | 0.6 | --- | 0.6 |
| Taxes other than income | 3.1 | 1.4 | --- | 4.5 |
| Operating income | $ 26.0 | $15.9 | $ --- | $41.9 |

| Three Months Ended September 30, 2008 (In millions) | Transportation and Storage | Gathering and Processing | Eliminations | Total |
|---|---|---|---|---|
| Operating revenues | $ 176.0 | $313.0 | $ (168.5 ) | $320.5 |
| Cost of goods sold | 130.0 | 250.8 | (168.5 ) | 212.3 |
| Gross margin on revenues | 46.0 | 62.2 | --- | 108.2 |
| Other operation and maintenance | 12.3 | 22.2 | --- | 34.5 |
| Depreciation and amortization | 4.4 | 9.5 | --- | 13.9 |

| | | | | |
|---|---|---|---|---|
| Taxes other than income | 3.1 | 1.1 | --- | 4.2 |
| Operating income | $ 26.2 | $29.4 | $ --- | $55.6 |

| Nine Months Ended September 30, 2009 (In millions) | Transportation and Storage | Gathering and Processing | Eliminations | Total |
|---|---|---|---|---|
| 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 | 15.2 | 32.0 | --- | 47.2 |
| Impairment of assets | 0.8 | 0.9 | --- | 1.7 |
| Taxes other than income | 9.9 | 4.2 | --- | 14.1 |
| Operating income | $ 71.2 | $ 35.1 | $ --- | $ 106.3 |

| Nine Months Ended September 30, 2008 (In millions) | Transportation and Storage | Gathering and Processing | Eliminations | Total |
|---|---|---|---|---|
| Operating revenues | $ 519.2 | $ 890.7 | $ (498.8) | $ 911.1 |
| Cost of goods sold | 404.4 | 690.2 | (498.8) | 595.8 |
| Gross margin on revenues | 114.8 | 200.5 | --- | 315.3 |
| Other operation and maintenance | 37.0 | 64.6 | --- | 101.6 |
| Depreciation and amortization | 12.8 | 27.1 | --- | 39.9 |
| Taxes other than income | 9.7 | 3.3 | --- | 13.0 |
| Operating income | $ 55.3 | $ 105.5 | $ --- | $ 160.8 |

Operating Data

| | Three Months Ended September 30, 2009 | Three Months Ended September 30, 2008 | Nine Months Ended September 30, 2009 | Nine Months Ended September 30, 2008 |
|---|---|---|---|---|
| New well connects (includes wells behind central receipt points) (A) | 65 | 101 | 176 | 289 |
| New well connects (excludes wells behind central receipt points) | 21 | 59 | 86 | 155 |
| Gathered volumes – TBtu/d (B) | 1.27 | 1.20 | 1.25 | 1.13 |
| Incremental transportation volumes – TBtu/d | 0.66 | 0.49 | 0.55 | 0.43 |
| Total throughput volumes – TBtu/d | 1.93 | 1.69 | 1.80 | 1.56 |
| Natural gas processed – TBtu/d | 0.74 | 0.67 | 0.69 | 0.65 |
| Natural gas liquids sold (keep-whole) – million gallons | 21 | 49 | 69 | 154 |
| Natural gas liquids sold (purchased for resale) – million gallons | 100 | 57 | 254 | 146 |
| Natural gas liquids sold (percent-of-liquids) – million gallons | 8 | 6 | 25 | 16 |
| Total natural gas liquids sold – million gallons | 129 | 112 | 348 | 316 |
| Average sales price per gallon | $ 0.735 | $ 1.465 | $ 0.677 | $ 1.459 |
| Estimated realized keep-whole spreads (C) | $ 3.73 | $ 6.94 | $ 3.40 | $ 7.05 |

(A) Includes wells behind central receipt points (as reported to management by third parties). A central receipt point is a single receipt point into a gathering line where a producer aggregates the volumes from one or more wells and delivers them into the gathering system at a single meter site.

(B) Incremental transportation volumes (reported in trillion British thermal units per day (“TBtu/d”)) 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, 2009 as Compared to Three Months Ended September 30, 2008

Operating Income

Enogex's operating income decreased approximately $13.7 million during the three months ended September 30, 2009 as compared to the same period in 2008 primarily due to a significantly lower gross margin in the gathering and processing business and a slightly lower gross margin in the transportation and storage business. Also contributing to the decrease in operating income was higher depreciation and amortization expense and an impairment of assets partially offset by lower operation and maintenance expenses.

Gross Margin

Enogex's consolidated gross margin decreased approximately $15.3 million during the three months ended September 30, 2009 as compared to the same period in 2008. The decrease resulted from a $13.4 million lower gross margin in the gathering and processing business and a $1.9 million lower gross margin in the transportation and storage business.

The transportation and storage business contributed approximately $44.1 million of Enogex's consolidated gross margin during the three months ended September 30, 2009 as compared to approximately $46.0 million during the same period in 2008, a decrease of approximately $1.9 million, or 4.1 percent. The transportation operations contributed approximately $35.7 million of Enogex's consolidated gross margin during the three months ended September 30, 2009 as compared to approximately $39.0 million during the same period in 2008. The storage operations contributed approximately $8.4 million of Enogex's consolidated gross margin during the three months ended September 30, 2009 as compared to approximately $7.0 million during the same period in 2008. The transportation and storage gross margin decreased during the three months ended September 30, 2009 as compared to the same period in 2008 primarily due to an increased imbalance liability, net of fuel recoveries, electric compression costs and natural gas length positions, associated with the transportation operations during the three months ended September 30, 2009, which decreased the gross margin by approximately $14.4 million. This decrease in the transportation and storage gross margin was partially offset by:

- a decrease in Enogex's over-recovered position under its FERC-approved fuel tracker in the East Zone during the three months ended September 30, 2009 while during the same period in 2008 the East Zone had an increase in its over-recovered position, which increased the gross margin by approximately $6.4 million; and
- an increase in demand fees associated with the new Section 311 firm service as well as the initiation of service under the MEP and Gulf Crossing capacity leases during the second quarter of 2009, which increased the gross margin by approximately $4.7 million.

The gathering and processing business (which for financial reporting purposes includes all of the Atoka Midstream, LLC joint venture ("Atoka") even though Enogex only owns a 50 percent interest in Atoka), contributed approximately $48.8 million of Enogex's consolidated gross margin during the three months ended September 30, 2009 as compared to approximately $62.2 million during the same period in 2008, a decrease of approximately $13.4 million, or 21.5 percent. The gathering operations contributed approximately $30.2 million of Enogex's consolidated gross margin during the three months ended September 30, 2009 as compared to approximately $20.1 million during the same period in 2008. The processing operations contributed approximately $18.6 million of Enogex's consolidated gross margin during the three months ended September 30, 2009 as compared to approximately $42.1 million during the same period in 2008. The gathering and processing gross margin decreased during the three months ended September 30, 2009 as compared to the same period in 2008 primarily due to:

a decrease in keep-whole margins associated with the processing operations primarily due to an approximate 58.8 percent decrease in keep-whole volumes from a shift to fixed fee and percent-of-liquids processing contracts and lower keep-whole spreads during the three months ended September 30, 2009, which decreased the gross margin by approximately $20.4 million;

a decrease in the percent-of-liquids margins associated with the processing operations, including Atoka, due to an approximate 58.6 percent decrease in NGLs pricing during the three months ended September 30, 2009 partially offset by an approximate 23.3 percent increase in volumes retained by Enogex due to a shift away from keep-whole processing contracts to percent-of-liquids processing contracts, which decreased the gross margin by approximately $5.7 million;

decreased sales of residue gas and NGLs associated with the processing operations of the Atoka joint venture as the result of a decline in natural gas and NGLs prices and an increase in the costs associated with third-party processing fees due to an increase in volumes being processed at a third-party plant, which decreased the gross margin by approximately $2.0 million; and a decrease in the condensate margin associated with the processing operations due to a 39.6 percent decrease in condensate prices partially offset by an approximate 15.2 percent increase in volumes due to several new projects that began production during 2008 and 2009, which decreased the gross margin by approximately $1.7 million.

These decreases in the gathering and processing gross margin were partially offset by:

a smaller increase in Enogex's net over-recovered position under its fuel tracker during the three months ended September 30, 2009 as compared to the same period in 2008, which increased the gross margin by approximately $3.8 million;
a decreased imbalance liability, net of fuel recoveries, electric compression costs and natural gas length positions, during the three months ended September 30, 2009, which increased the gross margin by approximately $3.2 million;
increased fixed fee margins associated with the processing operations primarily due to several new contracts, which increased the gross margin by approximately $2.7 million;
the termination of a margin sharing agreement on December 31, 2008, which increased the gross margin by approximately $2.1 million;
higher compression and dehydration fees associated with the gathering operations resulting from increased volumes from several new projects, including Atoka, which increased the gross margin by approximately $1.9 million; and
an increase in NGLs purchased for resale due to an approximate 72.0 percent increase in volumes due to several customers moving to fixed fee and percent-of-liquids processing contacts during the three months ended September 30, 2009, which increased the gross margin by approximately $1.3 million.

Operating Expenses

The aggregate of other operation and maintenance expenses, depreciation and amortization expense, impairment of assets and taxes other than income was approximately $1.6 million lower during the three months ended September 30, 2009 as compared to the same period in 2008. Depreciation and amortization expense increased approximately $2.6 million due to increased levels of depreciable plant in service.  Impairments of assets of approximately $0.6 million were recognized during the third quarter of 2009 primarily due to certain cancelled projects as some producers reduced the level of drilling activity due to the current economic environment.  Other operation and maintenance expenses decreased approximately $5.1 million primarily due to lower expenses for non-capitalized projects as a result of efforts to reduce operation and maintenance expenses and an increase in capitalized labor associated with capital projects during 2009.

Specifically, by segment, other operation and maintenance expenses for the transportation and storage business were approximately $2.5 million, or 20.3 percent, lower during the three months ended September 30, 2009 as compared to the same period in 2008 primarily due to the reversal of a reserve of approximately $1.5 million during the three months ended September 30, 2009 related to the dismissal of the Grynberg case as discussed in Note 12 of Notes to Condensed Consolidated Financial Statements.  The reserve in this matter was originally established with the 1999 acquisition of Transok, Inc. ("Transok"). Also contributing to the lower other operation and maintenance expenses was an approximate $1.4 million reduction in expenses for non-capitalized projects during the three months ended September 30, 2009.

Other operation and maintenance expenses for the gathering and processing business were approximately $2.6 million, or 11.7 percent, lower during the three months ended September 30, 2009 as compared to the same period in 2008 primarily due to an increase in allocated capitalized labor associated with capital projects during 2009.

Enogex Consolidated Information

Interest Expense. Enogex's consolidated interest expense was approximately $12.1 million during the three months ended September 30, 2009 as compared to approximately $8.2 million during the same period in 2008, an increase of approximately $3.9 million, or 47.6 percent. The increase in interest expense is primarily due to:

- an increase in interest expense of approximately $3.4 million on the $200 million of 6.875% 5-year senior notes issued in June 2009; and
- an increase in interest expense of approximately $2.8 million due to a tender payment on the tender offer Enogex completed in July 2009 related to the retirement of approximately $110.8 million of senior notes, which is a portion of Enogex's 8.125% senior notes due January 2010.

These increases in interest expense were partially offset by lower interest expense of approximately $1.7 million due to the retirement in July 2009 of approximately $110.8 million of senior notes, which is a portion of Enogex's 8.125% senior notes due January 2010.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was approximately $0.7 million during the three months ended September 30, 2009 as compared to approximately $1.9 million during the same period in 2008, a decrease of approximately $1.2 million, or 63.2 percent, due to lower earnings related to Atoka.

Income Tax Expense. Enogex's consolidated income tax expense was approximately $10.7 million during the three months ended September 30, 2009 as compared to approximately $17.8 million during the same period in 2008, a decrease of approximately $7.1 million, or 39.9 percent, primarily due to lower pre-tax income in the third quarter of 2009 as compared to the same period in 2008.

Non-recurring Items. Enogex had net income of approximately $18.1 million for the three months ended September 30, 2009, which includes a net loss of approximately $1.2 million for items the Company does not consider to be reflective of its ongoing operations. These decreases in Enogex's consolidated net income include:

a tender payment on the tender offer Enogex completed in July 2009 of approximately $1.7 million after-tax related to the retirement of approximately $110.8 million of senior notes, which is a portion of Enogex's 8.125% senior notes due January 2010; and

an impairment of certain long-lived assets of approximately $0.4 million after-tax.

These decreases were partially offset by the reversal of a reserve of approximately $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 12 of Notes to Condensed Consolidated Financial Statements.

Nine Months Ended September 30, 2009 as Compared to Nine Months Ended September 30, 2008

Operating Income

Enogex's operating income decreased approximately $54.5 million during the nine months ended September 30, 2009 as compared to the same period in 2008 primarily due to a lower gross margin in the gathering and processing business partially offset in part by a higher gross margin in the transportation and storage business. Also contributing to the decrease in operating income was higher depreciation and amortization expense, higher taxes other than income and an impairment of assets partially offset by lower operation and maintenance expenses.

Gross Margin

Enogex's consolidated gross margin decreased approximately $54.0 million during the nine months ended September 30, 2009 as compared to the same period in 2008. The decrease resulted from a $65.7 million lower gross margin in the gathering and processing business partially offset by an $11.7 million higher gross margin in the transportation and storage business.

The transportation and storage business contributed approximately $126.5 million of Enogex's consolidated gross margin during the nine months ended September 30, 2009 as compared to approximately $114.8 million during the same period in 2008, an increase of approximately $11.7 million, or 10.2 percent. The transportation operations contributed approximately $104.1 million of Enogex's consolidated gross margin during the nine months ended September 30, 2009 as compared to approximately $92.5 million during the same period in 2008. The storage operations contributed approximately $22.4 million of Enogex's consolidated gross margin during the nine months ended September 30, 2009 as compared to approximately $22.3 million during the same period in 2008. The transportation and storage gross margin increased during the nine months ended June 30, 2009 as compared to the same period in 2008 primarily due to:

- a decrease in Enogex's over-recovered position under its FERC-approved fuel tracker in the East Zone during the nine months ended September 30, 2009 while during the same period in 2008 the East Zone moved from an under-recovered position to an over-recovered position, which increased the gross margin by approximately $9.7 million;

increased crosshaul revenues due to increased volumes and rates as a result of shippers bidding up rates to move natural gas on Enogex's pipeline system during the nine months ended September 30, 2009, which increased the gross margin by approximately $5.2 million;
an increase in demand fees associated with the new Section 311 firm service as well as the initiation of service under the MEP and Gulf Crossing capacity leases, which was implemented during the second quarter of 2009, which increased the gross margin by approximately $4.7 million;
higher gross margins on commodity and interruptible fees during the nine months ended September 30, 2009 as compared to the same period in 2008 resulting from increased activity from several customers during the nine months ended September 30, 2009 and the implementation of new Section 311 firm service during the second quarter of 2009, which increased the gross margin by approximately $3.0 million;
higher gross margins on realized operational storage hedges during the nine months ended September 30, 2009 as compared to the same period in 2008, which increased the gross margin by approximately $2.6 million;
higher transportation fees as a result of an approximate 15.8 percent volume increase primarily due to several new gathering projects which began production in 2008 and 2009, which increased the gross margin by approximately $1.9 million; and
higher storage field losses during the nine months ended September 30, 2008 compared to the same period in 2009 due to lower natural gas prices in 2009, which increased the gross margin by approximately $1.5 million.

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

an increased imbalance liability, net of fuel recoveries, electric compression costs and natural gas length positions, associated with the transportation operations during the nine months ended September 30, 2009, which decreased the gross margin by approximately $12.1 million; and
a lower of cost or market adjustment to the natural gas storage inventory of approximately $5.8 million during the nine months ended September 30, 2009 as compared to an adjustment of approximately $0.7 million during the same period in 2008, which decreased the gross margin by approximately $5.1 million.

The gathering and processing business (which for financial reporting purposes includes all of the Atoka joint venture even though Enogex only owns a 50 percent interest in Atoka), contributed approximately $134.8 million of Enogex's consolidated gross margin during the nine months ended September 30, 2009 as compared to approximately $200.5 million during the same period in 2008, a decrease of approximately $65.7 million, or 32.8 percent. The gathering operations contributed approximately $81.6 million of Enogex's consolidated gross margin during the nine months ended September 30, 2009 as compared to approximately $66.3 million during the same period in 2008. The processing operations contributed approximately $53.2 million of Enogex's consolidated gross margin during the nine months ended September 30, 2009 as compared to approximately $134.2 million during the same period in 2008. The gathering and processing gross margin decreased during the nine months ended September 30, 2009 as compared to the same period in 2008 primarily due to:

a decrease in keep-whole margins associated with the processing operations primarily due to an approximate 57.7 percent decrease in keep-whole volumes from a shift to fixed fee and percent-of-liquids processing contracts and lower keep-whole spreads during the nine months ended September 30, 2009, which decreased the gross margin by approximately $68.1 million;
a decrease in the percent-of-liquids margins associated with the processing operations, including Atoka, due to an approximate 61.5 percent decrease in NGLs pricing during the nine months ended September 30, 2009 partially offset by an approximate 50.7 percent increase in volumes retained by Enogex, which decreased the gross margin by approximately $12.8 million;

a decrease in the condensate margin associated with the processing operations due to an approximate 53.1 percent decrease in condensate prices partially offset by an approximate 12.9 percent increase in volumes due to several new projects that began production during 2008 and 2009, which decreased the gross margin by approximately $10.6 million; and

decreased sales of residue gas and NGLs associated with the processing operations of the Atoka joint venture as the result of a decline in natural gas and NGLs prices and an increase in the costs associated with third-party processing fees due to an increase in volumes being processed at a third-party plant, which decreased the gross margin by approximately $5.9 million.

These decreases in the gathering and processing gross margin were partially offset by:

the termination of a margin sharing agreement on December 31, 2008, which increased the gross margin by approximately $9.9 million;

higher compression and dehydration fees associated with the gathering operations resulting from increased volumes from several projects, which increased the gross margin by approximately $6.4 million;
a smaller increase in Enogex's net over-recovered position under its fuel tracker during the nine months ended September 30, 2009 as compared to the same period in 2008, which increased the gross margin by approximately $4.5 million;
increased fixed fee margins associated with the processing operations primarily due to several new contracts, which increased the gross margin by approximately $3.9 million;
increased low pressure gathering fees associated with several projects, including Atoka, which increased the gross margin by approximately $2.7 million;
an increase in NGLs purchased for resale due to an approximate 71.0 percent increase in volumes due to several customers moving to fixed fee and percent-of-liquids processing contacts during the nine months ended September 30, 2009, which increased the gross margin by approximately $2.4 million;
increased high pressure gathering fees associated with several projects, which increased the gross margin by approximately $1.2 million; and
an increase in the condensate margin associated with the gathering operations due to a new treating facility that began production during the fourth quarter of 2008, which increased the gross margin by approximately $1.1 million.

Operating Expenses

The aggregate of other operation and maintenance expenses, depreciation and amortization expense, impairment of assets and taxes other than income was approximately $0.5 million higher during the nine months ended September 30, 2009 as compared to the same period in 2008. Depreciation and amortization expense increased approximately $7.3 million due to increased levels of depreciable plant in service. Impairments of assets of approximately $1.7 million were recognized during 2009 primarily due to certain cancelled projects as some producers reduced the level of drilling activity due to the current economic environment. Taxes other than income increased approximately $1.1 million due to an increase in ad valorem taxes. Other operation and maintenance expenses decreased approximately $9.6 million primarily due to overall lower expenses for non-capitalized projects as a result of efforts to reduce operation and maintenance expenses and an increase in capitalized labor associated with capital projects partially offset by higher equipment and compressor rental expense in 2009.

Specifically, by segment, other operation and maintenance expenses for the transportation and storage business were approximately $7.6 million, or 20.5 percent, lower during the nine months ended September 30, 2009 as compared to the same period in 2008 primarily due to an approximate $6.8 million reduction in expenses for non-capitalized projects during the nine months ended September 30, 2009. Also contributing to the lower other operation and maintenance expenses was the reversal of a reserve of approximately $1.5 million during the nine months ended September 30, 2009 related to the dismissal of the Grynberg case as discussed in Note 12 of Notes to Condensed Consolidated Financial Statements. The reserve in this matter was originally established with the 1999 acquisition of Transok.

Other operation and maintenance expenses for the gathering and processing business were approximately $2.0 million, or 3.1 percent, lower during the nine months ended September 30, 2009 as compared to the same period in 2008 primarily due to an increase in allocated capitalized labor in 2009 partially offset by an approximate $2.3 million increase in expenses for non-capitalized projects during the nine months ended September 30, 2009 in addition to higher equipment and compressor rental expense of approximately $1.2 million.

Enogex Consolidated Information

Interest Income. Enogex's consolidated interest income was approximately $0.1 million during the nine months ended September 30, 2009 as compared to approximately $2.2 million during the same period in 2008, a decrease of approximately $2.1 million, or 95.5 percent, primarily due to a decrease in interest earned as the balance of advances to OGE Energy and OERI decreased due to dividends, capital expenditures and repayment of the advances.

Interest Expense. Enogex's consolidated interest expense was approximately $24.4 million during the nine months ended September 30, 2009 as compared to approximately $24.8 million during the same period in 2008, a decrease of approximately $0.4 million, or 1.6 percent. The decrease in interest expense was primarily due to:

an increase in the amount of construction expenditures eligible for interest capitalization of approximately $4.0 million during the nine months ended September 30, 2009;

a decrease in interest expense to OGE Energy and OERI of approximately $1.8 million due to a decrease in credit support fees under the marketing and administrative services agreement between Enogex and OERI; and
lower interest expense of approximately $1.7 million due to the retirement in July 2009 of approximately $110.8 million of senior notes, which is a portion of Enogex's 8.125% senior notes due January 2010.

These decreases in interest expense were partially offset by:

an increase in interest expense of approximately $3.5 million on the $200 million of 6.875% 5-year senior notes issued in June 2009; and
an increase in interest expense of approximately $2.8 million due to a tender payment on the tender offer Enogex completed in July 2009 related to the retirement of approximately $110.8 million of senior notes, which is a portion of Enogex's 8.125% senior notes due January 2010.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was approximately $1.9 million during the nine months ended June 30, 2009 as compared to approximately $5.2 million during the same period in 2008, a decrease of approximately $3.3 million, or 63.5 percent, due to lower earnings related to Atoka.

Income Tax Expense. Enogex's consolidated income tax expense was approximately $30.2 million during the nine months ended September 30, 2009 as compared to approximately $51.7 million during the same period in 2008, a decrease of approximately $21.5 million, or 41.6 percent, primarily due to lower pre-tax income in the first nine months of 2009 as compared to the same period in 2008.

Non-recurring Items. Enogex had net income of approximately $49.5 million for the nine months ended September 30, 2009, which includes a net loss of approximately $1.9 million for items the Company does not consider to be reflective of its ongoing operations. These decreases in Enogex's consolidated net income include:

a tender payment on the tender offer Enogex completed in July 2009 of approximately $1.7 million after-tax related to the retirement of approximately $110.8 million of senior notes, which is a portion of Enogex's 8.125% senior notes due January 2010; and
an impairment of certain long-lived assets of approximately $1.1 million after-tax.

These decreases were partially offset by the reversal of a reserve of approximately $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 12 of Notes to Condensed Consolidated Financial Statements.

OERI (Natural Gas Marketing)

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 |
| (In millions) | | | | |
| Operating revenues | $127.2 | $394.9 | $436.7 | $1,317.8 |
| Cost of goods sold | 130.5 | 385.7 | 434.9 | 1,307.4 |
| Gross margin on revenues | (3.3) | 9.2 | 1.8 | 10.4 |
| Other operation and maintenance | 2.5 | 2.7 | 7.8 | 8.4 |
| Depreciation and amortization | --- | --- | --- | 0.1 |
| Taxes other than income | --- | --- | 0.3 | 0.3 |
| Operating income (loss) | $(5.8) | $6.5 | $(6.3) | $1.6 |

Three Months Ended September 30, 2009 as Compared to Three Months Ended September 30, 2008

Operating Income

OERI's operating loss was approximately $5.8 million during the three months ended September 30, 2009 as compared to operating income of approximately $6.5 million during the same period in 2008, an increase in the operating loss of approximately $12.3 million, primarily due to a lower gross margin.

Gross Margin

Gross margin was a loss of approximately $3.3 million during the three months ended September 30, 2009 as compared to a gain of approximately $9.2 million during the same period in 2008, a decrease in the gross margin of approximately $12.5 million. The gross margin decreased primarily due to:

- losses on economic hedges associated with storage contracts from recording these hedges at market value on September 30, 2009 as compared to gains from recording these hedges at market value on September 30, 2008, which decreased the gross margin by approximately $9.2 million;
- realized losses associated with various transportation contracts during the three months ended September 30, 2009 as compared to realized gains during the same period in 2008, which decreased the gross margin by approximately $7.5 million; and
- losses on physical trading during the three months ended September 30, 2009 as compared to gains during the same period in 2008, which decreased the gross margin by approximately $3.0 million.

These decreases in gross margin were partially offset by:

- a lower of cost or market adjustment to the natural gas storage inventory during the three months ended September 30, 2008 with no comparable adjustment during the same period in 2009, which increased the gross margin by approximately $5.9 million; and
- gains on economic hedges associated with various transportation contracts from recording these hedges at market value on September 30, 2009 as compared to losses from recording these hedges at market value on September 30, 2008, which increased the gross margin by approximately $1.2 million.

Additional Information

Income Tax Expense (Benefit). Income tax benefit was approximately $2.3 million during the three months ended September 30, 2009 as compared to income tax expense of approximately $2.6 million during the same period in 2008, an increase in the income tax benefit of approximately $4.9 million, primarily due to a pre-tax loss in the third quarter of 2009 as compared to pre-tax income during the same period in 2008.

Timing Items. OERI's net loss for the three months ended September 30, 2009 was approximately $3.7 million, which included a net loss of approximately $0.4 million resulting from recording hedges of natural gas inventory held in storage at market value on September 30, 2009. The offsetting gains from the sale of storage inventory are expected to be realized during the fourth quarter of 2009 and first quarter of 2010.

OERI's net income for the three months ended September 30, 2008 was approximately $4.0 million, which included a net loss of approximately $0.9 million resulting from recording economic hedges associated with various transportation contracts at market value on September 30, 2008. The offsetting gains from physical utilization of the transportation capacity and from the sale of storage inventory were realized during the remainder of 2008.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Operating Income

OERI's operating loss was approximately $6.3 million during the nine months ended September 30, 2009 as compared to operating income of approximately $1.6 million during the same period in 2008, an increase in the operating loss of approximately $7.9 million, primarily due to a lower gross margin.

Gross Margin

Gross margin was approximately $1.8 million during the nine months ended September 30, 2009 as compared to approximately $10.4 million during the same period in 2008, a decrease of approximately $8.6 million, or 82.7 percent. The gross margin decreased primarily due to:

- realized losses associated with various transportation contracts during the nine months ended September 30, 2009 as compared to realized gains during the same period in 2008, which decreased the gross margin by approximately $11.6 million;

- a decrease in gains on economic hedges associated with storage contracts from recording these hedges at market value on September 30, 2009 as compared to recording these hedges at market value on September 30, 2008, which decreased the gross margin by approximately $5.9 million;
- lower margin on withdrawals of natural gas from storage due to reduced capacity and lower prices, which decreased the gross margin by approximately $4.1 million; and
- losses on physical trading during the nine months ended September 30, 2009 as compared to gains during the same period in 2008, which decreased the gross margin by approximately $3.9 million.

These decreases in gross margin were partially offset by:

- gains on economic hedges associated with various transportation contracts from recording these hedges at market value on September 30, 2009 as compared to losses from recording these hedges at market value on September 30, 2008, which increased the gross margin by approximately $11.0 million; and
- a lower of cost or market adjustment to the natural gas storage inventory of approximately $0.3 million during the nine months ended September 30, 2009 as compared to an adjustment of approximately $5.9 million during the same period in 2008, which increased the gross margin by approximately $5.6 million.

Additional Information

Income Tax Expense (Benefit). Income tax benefit was approximately $2.6 million during the nine months ended September 30, 2009 as compared to income tax expense of approximately $0.9 million during the same period in 2008, an increase in the income tax benefit of approximately $3.5 million, primarily due to a pre-tax loss in the first nine months of 2009 as compared to pre-tax income during the same period in 2008.

Timing Items. OERI's net loss for the nine months ended September 30, 2009 was approximately $4.2 million, which included a net loss of approximately $0.3 million resulting from recording hedges of natural gas inventory held in storage at market value on September 30, 2009. The offsetting gains from physical utilization of the transportation capacity and from the sale of the storage inventory are expected to be realized during the fourth quarter of 2009 and first quarter of 2010.

OERI's net income for the nine months ended September 30, 2008 was approximately $1.3 million, which included a net loss of approximately $1.7 million resulting from recording hedges associated with various transportation contracts at market value on September 30, 2008. The offsetting gains from physical utilization of the transportation capacity and from the sale of the storage inventory were realized during the remainder of 2008.

Enogex's Non-GAAP Financial Measure

Enogex has included in this Form 10-Q the non-GAAP financial measure EBITDA. Enogex defines EBITDA as net income (excluding the Atoka noncontrolling interest) 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 generally accepted accounting principles ("GAAP"). The GAAP measure most directly comparable to EBITDA is net income (excluding the Atoka noncontrolling interest). The non-GAAP financial measure of EBITDA should not be considered as an alternative to GAAP net income (excluding the Atoka noncontrolling interest). 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 measure.

Reconciliation of EBITDA to net income attributable to Enogex LLC

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (In millions) | 2009 | 2008 | 2009 | 2008 |
| Net income attributable to Enogex LLC | $18.1 | $28.3 | $49.5 | $81.7 |
| Add: | | | | |
| Interest expense, net | 12.1 | 7.8 | 24.3 | 22.6 |
| Income tax expense | 10.7 | 17.8 | 30.2 | 51.7 |
| Depreciation and amortization | 16.5 | 13.9 | 47.2 | 39.9 |
| EBITDA | $57.4 | $67.8 | $151.2 | $195.9 |

Financial Condition

The balance of Cash and Cash Equivalents was approximately $2.3 million and $174.4 million at September 30, 2009 and December 31, 2008, respectively, a decrease of approximately $172.1 million, or 98.7 percent. See “Cash Flows” for a discussion of the changes in Cash and Cash Equivalents.

The balance of Accounts Receivable was approximately $285.3 million and $288.1 million at September 30, 2009 and December 31, 2008, respectively, a decrease of approximately $2.8 million, or 1.0 percent, primarily due to a decrease in natural gas prices and volumes at OERI partially offset by an increase in OG&E’s billings related to higher sales volumes and increased rates from the Oklahoma and Arkansas rate increases and an increase in NGLs prices at Enogex coupled with an increase in production from new Enogex projects that began production during 2008 and 2009.

The balance of Income Taxes Receivable was approximately $40.5 million at September 30, 2009 with no balance at December 31, 2008, primarily due to an accrual of a tax benefit based on the Company’s current estimates of a 2009 Federal tax net operating loss and a reclassification of the Federal tax benefit related to the estimated 2008 tax net operating loss from Accrued Taxes.

The balance of Fuel Inventories was approximately $108.1 million and $88.7 million at September 30, 2009 and December 31, 2008, respectively, an increase of approximately $19.4 million, or 21.9 percent, primarily due to a higher coal inventory balance due to higher average prices and planned outages at one of OG&E’s coal-fired power plants.

The balance of Fuel Clause Under Recoveries was approximately $0.3 million and $24.0 million at September 30, 2009 and December 31, 2008, respectively, a decrease of approximately $23.7 million, or 98.8 percent, primarily due to the fact that the amount billed to retail customers was higher 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 cost 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 Construction Work in Progress was approximately $553.2 million and $399.0 million at September 30, 2009 and December 31, 2008, respectively, an increase of approximately $154.2 million, or 38.6 percent, primarily due to costs associated with OU Spirit and the extra high voltage transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma being constructed by OG&E partially offset by assets being placed in service at Enogex during 2009.

The balance of Accounts Payable was approximately $174.7 million and $279.7 million at September 30, 2009 and December 31, 2008, respectively, a decrease of approximately $105.0 million, or 37.5 percent, primarily due to timing of outstanding checks clearing the bank at December 31, 2008, payments made in 2009 for Enogex project costs incurred at December 31, 2008, a decrease in natural gas prices and volumes at OERI and less purchased power at OG&E.

The balance of Accrued Taxes was approximately $60.6 million and $26.8 million at September 30, 2009 and December 31, 2008, respectively, an increase of approximately $33.8 million, primarily due to an increase in accrued ad valorem tax payments related to the timing of ad valorem tax payments as well as an increase related to the Company owning more property in 2009 and a reclassification of the Federal tax benefit related to the estimated 2008 tax net operating loss to Income Taxes Receivable.

The balance of Accrued Interest was approximately $30.8 million and $48.7 million at September 30, 2009 and December 31, 2008, respectively, a decrease of approximately $17.9 million, or 36.8 percent, primarily due to the timing of interest payments on long-term debt in 2009 partially offset by additional interest accrued on long-term debt.

The balance of Long-Term Debt Due Within One Year was approximately $289.4 million at September 30, 2009 with no balance at December 31, 2008, primarily due to the classification of Enogex's medium-term senior notes as a current liability as they mature in January 2010. On July 23, 2009, Enogex purchased approximately $110.8 million principal amount of the $400.0 million medium-term senior notes due January 2010 and those repurchased notes were retired and cancelled (see Note 8 for a further discussion). The remaining balance of Enogex's medium-term senior notes is approximately $289.2 million at September 30, 2009.

The balance of Gas Imbalances was approximately $9.7 million and $24.9 million at September 30, 2009 and December 31, 2008, respectively, a decrease of approximately $15.2 million, or 61.0 percent. The Gas Imbalance liability is comprised of planned or managed imbalances related to OERI's business, referred to as park and loan transactions, and pipeline and natural gas liquids imbalances, which are operational imbalances. Park and loan transactions were approximately $3.0 million at December 31, 2008 with no comparable balance at September 30, 2009. Operational imbalances decreased approximately $12.2 million primarily due to a decrease in Enogex's over-recovered position under its FERC-approved fuel tracker coupled with a decrease in the balancing agreements liability at December 31, 2008.

The balance of Fuel Clause Over Recoveries was approximately $176.4 million and $8.6 million at September 30, 2009 and December 31, 2008, respectively, an increase of approximately $167.8 million, primarily due to the fact that the amount billed to retail customers was higher 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 cost 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. As part of the OCC order in OG&E's Oklahoma rate case, OG&E will refund approximately $114.9 million in fuel clause over recoveries to its Oklahoma customers over the next 10 months.

The balance of Other Current Liabilities was approximately $43.4 million and $62.2 million at September 30, 2009 and December 31, 2008, respectively, a decrease of approximately $18.8 million, or 30.2 percent, primarily due to a reduction in the liability for a storage agreement at OERI resulting from a withdrawal of natural gas from storage at the end of the contract term, a margin call payment to an OERI counterparty that was accrued at December 31, 2008 with no corresponding item at September 30, 2009 and a reduction in liability for a margin sharing agreement at Enogex.

The balance of Long-Term Debt was approximately $1.9 billion and $2.2 billion at September 30, 2009 and December 31, 2008, respectively, a decrease of approximately $0.3 billion, or 13.6 percent. The decrease was primarily due to the classification of Enogex's $400.0 million medium-term senior notes as a current liability in January 2009 as they mature in January 2010 in addition to lower outstanding borrowings of approximately $30.0 million under Enogex's revolving credit agreement partially offset by the issuance of $200.0 million in long-term debt by Enogex in June 2009.

The balance of Accrued Benefit Obligations was approximately $318.1 million and $350.5 million at September 30, 2009 and December 31, 2008, respectively, a decrease of approximately $32.4 million, or 9.2 percent, primarily due to pension plan contributions in 2009.

The balance of Accumulated Deferred Income Taxes was approximately $1,096.1 million and $996.9 million at September 30, 2009 and December 31, 2008, respectively, an increase of approximately $99.2 million, or 10.0 percent, primarily due to accelerated bonus tax depreciation which resulted in higher Federal and state deferred tax accruals.

The balance of Other Deferred Credits and Other Liabilities was approximately $54.9 million and $34.9 million at September 30, 2009 and December 31, 2008, respectively, an increase of approximately $20.0 million, or 57.3 percent, primarily due to payments Enogex received from a third party which will be used by Enogex for the construction of a pipeline.

The balance of Accumulated Other Comprehensive Loss was approximately $57.2 million and $13.7 million at September 30, 2009 and December 31, 2008, respectively, an increase of approximately $43.5 million, primarily due to hedging losses at Enogex.

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 Annual Report on Form 10-K for the year ended December 31, 2008 ("2008 Form 10-K").

OG&E Railcar Lease Agreement

At December 31, 2008, OG&E had a noncancellable operating lease with purchase options, covering 1,464 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 value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of approximately $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 expires with respect to 135 railcars on March 5, 2010. The lease agreement with respect to the remaining 135 railcars will expire on November 2, 2009, six months from the date those railcars entered OG&E's service on May 2, 2009.

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.

At September 30, 2009, the Company had approximately $2.3 million of cash and cash equivalents. At September 30, 2009, the Company had approximately $825.9 million of net available liquidity under its revolving credit agreements.

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 Enogex. 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. Future collateral requirements are uncertain, and are subject to terms of the specific agreements and to fluctuations in natural gas and NGLs market prices.

Cash Flows

| Nine Months Ended September 30 (In millions) | 2009 | 2008 |
| --- | --- | --- |
| Net cash provided from operating activities | $459.5 | $178.2 |
| Net cash used in investing activities | (675.6) | (914.6) |
| Net cash provided from financing activities | 44.0 | 932.5 |

The increase of approximately $281.3 million in net cash provided from operating activities during the nine months ended September 30, 2009 as compared to the same period in 2008 was primarily due to:

- higher fuel recoveries at OG&E during the nine months ended September 30, 2009 as compared to the same period in 2008;
- cash received during the nine months ended September 30, 2009 from the implementation of the Redbud Facility rider in the third quarter of 2008;

- cash receipts during the nine months ended September 30, 2009 from the implementation of the Oklahoma rate increase in August 2009; and
- payments made by OG&E in the first quarter of 2008 related to the December 2007 ice storm.

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

- a decrease in sales and purchases at Enogex and OERI due to a decrease in natural gas prices and volumes in the first nine months of 2009 as compared to the same period in 2008; and
- a decrease in cash collateral posted by counterparties and held by OERI related to OERI's existing NGL hedge positions.

The decrease of approximately $239.0 million in net cash used in investing activities during the nine months ended September 30, 2009 as compared to the same period in 2008 primarily related to higher levels of capital expenditures in 2008 primarily related to the purchase of the Redbud Facility in September 2008 partially offset by capital expenditures in 2009 related to OU Spirit and the extra high voltage transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma being constructed by OG&E.

The decrease of approximately $888.5 million in net cash provided from financing activities during the nine months ended September 30, 2009 as compared to the same period in 2008 primarily related to:

- lower levels of short-term debt during the nine months ended September 30, 2009;
- proceeds received from the issuance of $200 million in long-term debt by OG&E in January 2008 and $250 million in September 2008;
- the retirement of approximately $110.8 million in long-term debt at Enogex related to the tender offer discussed below; and
- lower levels of borrowings and a higher level of repayments under Enogex's revolving credit agreement during the nine months ended September 30, 2009.

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

- proceeds received from the issuance of $200 million in long-term debt by Enogex in June 2009; and
- an increase in the issuance of common stock during the nine months ended September 30, 2009.

Future Capital Requirements

Capital Expenditures

The Company's consolidated estimates of capital expenditures are approximately: 2009 - $861 million, 2010 - $617 million, 2011 - $567 million, 2012 - $513 million, 2013 - $470 million and 2014 - $400 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"). The table below summarizes the capital expenditures by category:

| (In millions) | Total | 2009 | 2010-2011 | 2012-2013 | 2014 |
|---|---|---|---|---|---|
| OG&E Base Transmission | $167 | $43 | $73 | $28 | $23 |
| OG&E Base Distribution | 1,266 | 163 | 452 | 434 | 217 |
| OG&E Base Generation | 276 | 38 | 82 | 103 | 53 |
| OG&E Other | 139 | 12 | 49 | 52 | 26 |
| Total OG&E Base Transmission, Distribution, Generation and Other | 1,848 | 256 | 656 | 617 | 319 |
| OG&E Known and Committed Projects: | | | | | |
| Smart Grid Program | 19 | 6 | 13 | --- | --- |
| Sunnyside-Hugo (345 kV) | 120 | 1 | 81 | 38 | --- |
| Sooner-Rose Hill (345 kV) | 68 | 1 | 67 | --- | --- |
| Oklahoma City, OK to Woodward, OK (345 kV) | 179 | 156 | 23 | --- | --- |
| OG&E System Hardening | 35 | 2 | 33 | --- | --- |
| OG&E OU Spirit | 234 | 200 | 34 | --- | --- |
| OG&E Balanced Portfolio 3E Projects | 285 | --- | 70 | 199 | 16 |
| OG&E Other | 34 | --- | 34 | --- | --- |
| Total OG&E Known and Committed Projects | 974 | 366 | 355 | 237 | 16 |
| Total OG&E (A) | 2,822 | 622 | 1,011 | 854 | 335 |
| OGE Energy and OERI | 106 | 10 | 37 | 39 | 20 |
| Enogex (Base Maintenance and Known and Committed Projects) (B) | 500 | 229 | 136 | 90 | 45 |
| Total Consolidated | $3,428 | $861 | $1,184 | $983 | $400 |

(A) 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 (see Note 12 of Notes to Condensed Consolidated Financial Statements for a further discussion).
(B) Enogex's capital expenditures for 2009 and 2010 include approximately $56 million related to construction of a pipeline and compressor station that Enogex is completing on behalf of a third party in which Enogex will be reimbursed for the capital expenditures.

Additional capital expenditures beyond those identified in the chart above, including additional incremental growth opportunities in transmission assets, wind generation 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 chart above reflect base market conditions at October 29, 2009 and do not reflect the potential opportunity for a set of growth projects that could materialize if natural gas prices rise in the future.

Pension Plan Funding

In the third quarter of 2009, the Company contributed approximately $10 million to its pension plan for a total contribution of approximately $50 million to its pension plan during 2009.  No additional contributions are expected in 2009.

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. 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 for capital expenditures until permanent financing is arranged.

Short-Term Debt

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 loans under short-term bank facilities. The short-term debt balance was approximately $308.0 million and $298.0 million at September 30, 2009 and December 31, 2008, respectively. Included in the September 30, 2009 short-term debt balance is approximately $149 million in outstanding borrowings under OGE Energy's revolving credit agreement and approximately $159 million in outstanding commercial paper borrowings at OGE Energy. The December 31, 2008 short-term debt balance of approximately $298.0 million is comprised entirely of outstanding borrowings under OGE Energy's revolving credit agreement. At September 30, 2009 and December 31, 2008, respectively, Enogex had approximately $90.0 million and $120.0 million in outstanding borrowings under its revolving credit agreement. As Enogex's borrowings are not expected to be repaid within the next 12 months, they are classified as long-term debt for financial reporting purposes. The following table provides information regarding the Company's revolving credit agreements and available cash at September 30, 2009.

Revolving Credit Agreements and Available Cash (In millions)

| Entity | Aggregate Commitment | Amount Outstanding | Weighted-Average Interest Rate | Maturity |
|---|---|---|---|---|
| OGE Energy | $596.0 | $308.0 | 0.43% | December 6, 2012 |
| OG&E | 389.0 | 11.1 | ---% | December 6, 2012 |
| Enogex | 250.0 | 90.0 | 0.57% | March 31, 2013 |
| | 1,235.0 | 409.1 | 0.46% | |
| Cash | 2.3 | N/A | N/A | N/A |
| Total | $1,237.3 | $409.1 | 0.46% | |

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

Enogex's Refinancing of Long-Term Debt and Tender Offer

On June 24, 2009, Enogex issued $200 million of 6.875% 5-year senior notes in a transaction exempt from the registration requirements of the Securities Act of 1933. Enogex applied a portion of the net proceeds from the sale of the new notes to pay the purchase price in the tender offer discussed below for its 8.125% notes due January 2010 with the remainder of the net proceeds being used to repay a portion of Enogex's borrowings under its revolving credit agreement and for general corporate purposes. The refinancing of the balance of Enogex's 8.125% notes due January 2010 is expected to occur later in the fourth quarter of 2009. At this time, the Company cannot predict how interest rates will affect its ability to obtain financing on favorable terms.

Also on June 24, 2009, Enogex commenced a cash tender offer for up to $150 million principal amount of its 8.125% senior notes due January 2010. The tender offer for the 8.125% senior notes due January 2010 expired on July 22, 2009. The total consideration per $1,000 principal amount of the 8.125% senior notes due January 2010 validly tendered and not withdrawn was $1,027.50. Pursuant to the tender offer, on July 23, 2009, Enogex purchased approximately $110.8 million principal amount of the 8.125% senior notes due January 2010 and those repurchased notes were retired and cancelled.

Expected Issuance of OG&E Long-Term Debt

OG&E expects to issue between $200 million and $250 million of long-term debt in mid-2010, depending on market conditions, to fund capital expenditures.

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 2008 Form 10-K.

Accounting Pronouncements

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

Commitments and Contingencies

Except as disclosed otherwise in this Form 10-Q and the Company's 2008 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 12 and 13 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q and Notes 15 and 16 of Notes to Consolidated Financial Statements and Item 3 of Part I of the 2008 Form 10-K for a discussion of the Company's commitments and contingencies.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Except as set forth below, the market risks set forth in Part II, Item 7A of the Company's 2008 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 OGE Energy's natural gas marketing subsidiary, OGE Energy Resources, Inc. ("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. 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 over the next 12 months. The result of this analysis, which may differ from actual results, is as follows at September 30, 2009.

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

Non-Trading Activities

The prices of natural gas, natural gas liquids ("NGL") 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 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.

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, 2009.

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

Management may designate certain derivative instruments for the purchase or sale of physical commodities, purchase or sale of electric power and fuel procurement as normal purchases and normal sales contracts. 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 its gathering and processing business; (iii) electric power contracts by OG&E; and (iv) fuel procurement by OG&E.

Credit Risk

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.

The Company has credit policies with regard to its counterparties that management believes minimize overall credit risk. These policies include the evaluation of a potential counterparty's financial position (including credit rating, if available), collateral requirements under certain circumstances, the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty and the monitoring of the financial position of existing counterparties on an ongoing basis.

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 2008 Form 10-K for a description of certain legal proceedings presently pending. Except as set forth below and in Notes 12 and 13 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q, there are no new significant cases to report against the Company or its subsidiaries and there have been no material changes in the previously reported proceedings.

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

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

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

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

On October 20, 2006, the District Court of Wyoming ruled on Grynberg's district court appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex Services Corp., Transok, Inc. ("Transok") and OG&E, for lack of subject matter jurisdiction. Judgment was entered on November 17, 2006. The defendants filed motions for attorneys' fees and other legal costs on various bases. A hearing on these motions was held on April 24, 2007, at which time the judge took these motions under advisement. On November 15, 2006, Grynberg filed appeals with the Tenth Circuit Court of Appeals. On March 17, 2009, the Tenth Circuit Court of Appeals affirmed the October 2006 order of the District Court of Wyoming dismissing the complaints against all gas defendants, including all Company parties. On April 14, 2009, Grynberg filed a petition for rehearing in the Tenth Circuit Court of Appeals. By order dated May 4, 2009, the Tenth Circuit Court denied Grynberg's request for rehearing. Grynberg filed a petition for writ of certiorari in the U.S. Supreme Court on August 3, 2009. By order dated October 5, 2009, the U.S. Supreme Court denied Grynberg's petition for writ of certiorari. This ruling concludes the appeal of the October 2006 order of the District Court of Wyoming dismissing complaints against all gas defendants, including all Company parties. The Company now considers this case closed and, as a result, during the third quarter of 2009, Enogex reversed a reserve of approximately $1.5 million that was originally established with the 1999 acquisition of Transok.

2. 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 subsidiary entities remained as defendants. The plaintiffs' Fourth Amended Petition seeks class certification and alleges that approximately 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 reconsideration of the court's denial of class certification.

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.

3. 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 reconsideration of the court's denial of class certification.

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.

4. 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. OG&E filed a writ of prohibition at the Oklahoma Supreme Court asking the court to direct the trial court to dismiss the class action suit. 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 authorized OG&E to collect the challenged franchise fee charges. A procedural schedule and notice requirements for the matter were established by the OCC on December 4, 2008. On March 10, 2009, the Oklahoma Attorney General, OG&E, OG&E Shareholders Association and the Staff of the Public Utility Division of the OCC all filed briefs arguing that the application should be dismissed. A hearing on the motion to dismiss was held before the administrative law judge ("ALJ") on March 26, 2009. On June 30, 2009, the ALJ issued a report recommending that the application be dismissed. On July 9, 2009, the applicants filed a Notice of Appeal and a hearing on this matter is scheduled for November 5, 2009. OG&E believes that this case is without merit.

Item 1A. Risk Factors.

Except as discussed below, there have been no significant changes in the Company's risk factors from those discussed in the Company's 2008 Form 10-K.

Costs of compliance with environmental laws and regulations are significant and the cost of compliance with future environmental laws and regulations may adversely affect our results of operations, consolidated financial position, or liquidity.

We are subject to extensive Federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife mortality, natural resources and health and safety that could, among other things, restrict or limit the output of certain facilities or the use of certain fuels required for the production of electricity and/or require additional pollution control equipment and otherwise increase costs. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future.

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 ("RICE MACT Amendments"). Depending on the final regulations that may be enacted by the EPA for the RICE MACT Amendments, Enogex and OG&E facilities will likely be impacted. The costs that may be incurred to comply with these regulations, including the testing and modification of the affected engines, are uncertain at this time. The current proposed compliance deadline is three years from the effective date of the final rules.

There is inherent risk of the incurrence of environmental costs and liabilities in our operations due to our handling of natural gas, air emissions related to our operations and historical industry operations and waste disposal practices. For example, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. We may be able to recover these costs from insurance. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary.

There also is growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation and regulation at the Federal level, actions at the state level, litigation relating to greenhouse gas emissions and pressure for greenhouse gas emission reductions from investor organizations and the international community. Recently, two Federal courts of appeal have reinstated nuisance-type claims against emitters of carbon dioxide, including several utility companies, alleging that such emissions contribute to global warming. On April 17, 2009, the EPA issued a proposed finding that greenhouse gases contribute to air pollution that may endanger public health or welfare. The proposed finding identified six greenhouse gases that pose a potential threat: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride. The EPA is considering public comments on the proposed finding. On September 15, 2009, the EPA proposed rules to reduce greenhouse gas emissions from light-duty vehicles. Final adoption of the proposed standards for light-duty vehicles is contingent on the EPA first finalizing its proposed endangerment finding for greenhouse gas emissions from motor vehicles.

In June 2009, the American Clean Energy and Security Act of 2009 (sometimes referred to as the Waxman-Markey global climate change bill) was passed in the U.S. House of Representatives. The bill includes many provisions that would potentially have a significant impact on the Company and its customers. The bill proposes a cap and trade regime, a renewable portfolio standard, electric efficiency standards, revised transmission policy and mandated investments in plug-in hybrid infrastructure and smart grid technology. Although proposals have been introduced in the U.S. Senate, including a proposal that would require greater reductions in greenhouse gas emissions than the American Clean Energy and Security Act of 2009, it is uncertain at this time whether, and in what form, legislation will be adopted by the U.S. Senate. Both President Obama and the Administrator of the EPA have repeatedly indicated their preference for comprehensive legislation to address this issue and create the framework for a clean energy economy. Compliance with any new laws or regulations regarding the reduction of greenhouse gases could result in significant changes to the Company’s operations, significant capital expenditures by the Company and a significant increase in its cost of conducting business.

On September 22, 2009, the EPA announced the adoption of the first comprehensive national system for reporting emissions of carbon dioxide and other greenhouse gases produced by major sources in the United States. The new reporting requirements will apply to suppliers of fossil fuel and industrial chemicals, manufacturers of motor vehicles and engines, as well as large direct emitters of greenhouse gases with emissions equal to or greater than a threshold of 25,000 metric tons per year, which includes certain OG&E and Enogex facilities. The rule requires the collection of data beginning on January 1, 2010 with the first annual reports due to the EPA on March 31, 2011. Certain reporting requirements included in the initial proposed rules that may have significantly affected capital expenditures were not included in the final reporting rule. Additional requirements have been reserved for further review by the EPA with additional rulemaking possible. The outcome of such review and cost of compliance of any additional requirements is uncertain at this time.

On September 30, 2009, the EPA proposed two rules related to the control of greenhouse gas emissions. The first proposal, which is related to the prevention of significant deterioration and Title V tailoring, determines what sources would be affected by requirements under the Federal Clean Air Act programs for new and modified sources to control emissions of carbon dioxide and other greenhouse gas emissions. The second proposal addresses the December 2008 prevention of significant deterioration interpretive memo by the EPA, which declared that carbon dioxide is not covered by the prevention of significant deterioration provisions of the Federal Clean Air Act. The outcome of these proposals is uncertain at this time.

Oklahoma and Arkansas have not, at this time, established any mandatory programs to regulate carbon dioxide and other greenhouse gases. However, government officials in these states have declared support for state and Federal action on climate change issues. OG&E reports quarterly its carbon dioxide emissions and is continuing to evaluate various options for reducing, avoiding, off-setting or sequestering its carbon dioxide emissions. Enogex is a partner in the EPA Natural Gas STAR Program, a voluntary program to reduce methane emissions. 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 on generation facilities to address climate change, this could result in significant additional compliance costs that would affect our future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

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

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

| Period | Total Number of Shares Purchased | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plan | Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan |
|---|---|---|---|---|
| 7/1/09 – 7/31/09 | 142,600 | $ 28.70 | N/A | N/A |
| 8/1/09 – 8/31/09 | 61,700 | $ 31.39 | N/A | N/A |
| 9/1/09 – 9/30/09 | 17,800 | $ 31.39 | N/A | N/A |

N/A – not applicable

Item 6. Exhibits.

| Exhibit No. | Description |
|---|---|
| 31.01 | Certifications Pursuant to Rule 13a-14(a)/15d-14(a) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.01 | Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 99.01 | Copy of Settlement Agreement dated July 2, 2009. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 6, 2009 (File No. 1-12579) and incorporated by reference herein) |
| 99.02 | Copy of OCC Order dated July 24, 2009. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 30, 2009 (File No. 1-12579) and incorporated by reference herein) |

SIGNATURE

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

OGE ENERGY CORP.
(Registrant)

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

October 30, 2009