OGE ENERGY CORP.
Form 10-Q
May 06, 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 March 31, 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 (§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 March 31, 2009, 96,037,234 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED MARCH 31, 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", "intend", "objective", "plan", "possible", "potential", "project" and similar expressions. Actual results may va materially. In addition to the specific risk factors discussed in "Item 1A. Risk Factors" in OGE Energy Corp.'s Annual Report on Form 10-K for the year ended December 31, 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 regulated accounting principles under Financial Accounting Standards Board Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation";
- creditworthiness of suppliers, customers and other contractual parties;
- the higher degree of risk associated with the Company's nonregulated business compared with the Company's regulated utility business; and
- other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission including those listed in "Item 1A. Risk Factors" and in Exhibit 99.01 to the Company's 2008 Form 10-K.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

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

	Three Months Ended March 31,	
(In millions, except per share data)	**2009**	2008
OPERATING REVENUES		
Electric Utility operating revenues	**$336.7**	$386.4
Natural Gas Pipeline operating revenues	**269.9**	608.3
Total operating revenues	**606.6**	994.7
COST OF GOODS SOLD (exclusive of depreciation and amortization shown below)		
Electric Utility cost of goods sold	**159.1**	228.8
Natural Gas Pipeline cost of goods sold	**194.1**	520.0
Total cost of goods sold	**353.2**	748.8
Gross margin on revenues	**253.4**	245.9
Other operation and maintenance	**116.5**	125.2
Depreciation and amortization	**62.6**	50.7
Taxes other than income	**22.3**	21.9
OPERATING INCOME	**52.0**	48.1
OTHER INCOME (EXPENSE)		
Interest income	**0.7**	0.9
Allowance for equity funds used during construction	**1.3**	---
Other income	**6.5**	3.9
Other expense	**(2.3)**	(2.5)
Net other income	**6.2**	2.3
INTEREST EXPENSE		
Interest on long-term debt	**31.4**	23.4
Allowance for borrowed funds used during construction	**(1.1)**	(0.7)
Interest on short-term debt and other interest charges	**2.4**	6.5
Interest expense	**32.7**	29.2
INCOME BEFORE TAXES	**25.5**	21.2
INCOME TAX EXPENSE	**7.9**	6.6
NET INCOME	**17.6**	14.6
Less: Net income attributable to noncontrolling interest	**0.8**	1.6
NET INCOME ATTRIBUTABLE TO OGE ENERGY	**$16.8**	$13.0
BASIC AVERAGE COMMON SHARES OUTSTANDING	**94.7**	91.9
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**95.3**	92.5
BASIC EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	**$0.18**	$0.14
DILUTED EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	**$0.18**	$0.14

DIVIDENDS DECLARED PER SHARE	**$0.3550**	$0.347

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

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OGE ENERGY CORP.

CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions)	**March 31, 2009 (Unaudited)**	December 31, 2008
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 146.4**	$ 174.4
Accounts receivable, less reserve of $2.9 and $3.2, respectively	**239.4**	288.1
Accrued unbilled revenues	**41.1**	47.0
Fuel inventories	**94.6**	88.7
Materials and supplies, at average cost	**76.2**	72.1
Price risk management	**11.9**	11.9
Gas imbalances	**1.5**	6.2
Accumulated deferred tax assets	**21.8**	14.9
Fuel clause under recoveries	**---**	24.0
Prepayments	**8.4**	9.0
Other	**6.4**	8.3
Total current assets	**647.7**	744.6
OTHER PROPERTY AND INVESTMENTS, at cost	**38.6**	42.2
PROPERTY, PLANT AND EQUIPMENT		
In service	**7,879.0**	7,722.4
Construction work in progress	**478.8**	399.0
Total property, plant and equipment	**8,357.8**	8,121.4
Less accumulated depreciation	**2,911.5**	2,871.6
Net property, plant and equipment	**5,446.3**	5,249.8
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**15.2**	14.6
Regulatory asset – SFAS No. 158	**337.9**	344.7
Price risk management	**23.3**	22.0
McClain Plant deferred expenses	**4.7**	6.2
Unamortized loss on reacquired debt	**17.4**	17.7
Unamortized debt issuance costs	**13.3**	13.5
Other	**63.1**	63.2
Total deferred charges and other assets	**474.9**	481.9
TOTAL ASSETS	**$ 6,607.5**	$ 6,518.5

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

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OGE ENERGY CORP.

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(In millions)	**March 31, 2009 (Unaudited)**	December 31, 2008
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 351.5**	$ 298.0
Accounts payable	**219.7**	279.7
Dividends payable	**34.1**	33.2
Customer deposits	**59.7**	58.8
Accrued taxes	**0.9**	26.8
Accrued interest	**32.5**	48.7
Accrued compensation	**29.2**	45.2
Long-term debt due within one year	**400.7**	---
Price risk management	**13.5**	2.3
Gas imbalances	**16.6**	24.9
Fuel clause over recoveries	**73.0**	8.6
Other	**37.4**	62.2
Total current liabilities	**1,268.8**	888.4
LONG-TERM DEBT	**1,841.0**	2,161.8
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**355.4**	350.5
Accumulated deferred income taxes	**1,005.1**	996.9
Accumulated deferred investment tax credits	**16.3**	17.3
Accrued removal obligations, net	**153.3**	150.9
Price risk management	**8.6**	3.8
Other	**33.1**	34.9
Total deferred credits and other liabilities	**1,571.8**	1,554.3
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**858.7**	802.9
Retained earnings	**1,090.2**	1,107.6
Accumulated other comprehensive loss, net of tax	**(41.0)**	(13.7)
Total OGE Energy stockholders' equity	**1,907.9**	1,896.8
Noncontrolling interest	**18.0**	17.2
Total stockholders' equity	**1,925.9**	1,914.0

TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$**	**6,607.5**	$	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)

(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**
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 partners	---	---	---	---	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

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

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

(In millions)	**Three Months Ended March 31, 2009**	2008
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	**$ 17.6**	$ 14.6
Adjustments to reconcile net income to net cash provided from (used in) operating activities		
Depreciation and amortization	**62.6**	50.7
Deferred income taxes and investment tax credits, net	**18.9**	14.3
Allowance for equity funds used during construction	**(1.3)**	---
Loss on disposition of assets	**0.2**	---
Stock-based compensation expense	**1.4**	1.1
Stock-based compensation converted to cash for tax withholding	**(1.8)**	---
Price risk management assets	**(1.3)**	(2.8)
Price risk management liabilities	**(30.4)**	6.4
Other assets	**10.6**	7.6
Other liabilities	**(3.0)**	(3.6)
Change in certain current assets and liabilities		
Accounts receivable, net	**48.7**	(8.7)
Accrued unbilled revenues	**5.9**	8.5
Fuel, materials and supplies inventories	**(10.0)**	4.5
Gas imbalance assets	**4.7**	1.0
Fuel clause under recoveries	**24.0**	(2.8)
Other current assets	**2.5**	1.2
Accounts payable	**(60.0)**	(45.5)
Customer deposits	**0.9**	1.2
Accrued taxes	**(25.9)**	(20.8)
Accrued interest	**(16.2)**	(12.2)
Accrued compensation	**(16.0)**	(28.4)
Gas imbalance liabilities	**(8.3)**	0.7
Fuel clause over recoveries	**64.4**	---
Other current liabilities	**(24.8)**	(3.8)
Net Cash Provided from (Used in) Operating Activities	**63.4**	(16.8)
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures (less allowance for equity funds used during construction)	**(247.8)**	(125.9)
Proceeds from sale of assets	**0.1**	0.1
Net Cash Used in Investing Activities	**(247.7)**	(125.8)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from line of credit	**80.0**	---
Issuance of common stock	**56.1**	0.2
Increase (decrease) in short-term debt, net	**53.5**	(29.5)
Proceeds from long-term debt	**---**	197.2
Contributions from partners	**---**	0.5
Dividends paid on common stock	**(33.3)**	(31.9)

Net Cash Provided from Financing Activities	**156.3**	136.5
NET DECREASE IN CASH AND CASH EQUIVALENTS	**(28.0)**	(6.1)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**174.4**	8.8
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 146.4**	$ 2.7

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") is a provider 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: (1) natural gas transportation and storage and (2) natural gas gathering and processing. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream, LLC joint venture ("Atoka") through Enogex Atoka LLC, a wholly owned subsidiary of Enogex.

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 to construct high-capacity transmission line projects in western Oklahoma. The Company owns 50 percent of the joint venture. The joint venture is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. Work on the joint venture projects is scheduled to begin in late 2009 and is targeted for completion by the end of 2013.

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 March 31, 2009 and December 31, 2008, the results of its operations for the three months ended March 31, 2009 and 2008, and the results of its cash flows for the three months ended March 31, 2009 and 2008, have been included and are of a normal recurring nature except as otherwise disclosed.

Due to seasonal fluctuations and other factors, the operating results for the three months ended March 31, 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 the accounting principles prescribed by the Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 provides that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

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

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

(In millions)	**March 31, 2009**	December 31, 2008
Regulatory Assets		
Regulatory asset – SFAS No. 158	**$ 337.9**	$ 344.7
Deferred storm expenses	**30.8**	32.2
Unamortized loss on reacquired debt	**17.4**	17.7
Deferred pension plan expenses	**15.7**	14.6
Income taxes recoverable from customers, net	**15.2**	14.6
Red Rock deferred expenses	**7.6**	7.4
McClain Plant deferred expenses	**4.7**	6.2
Fuel clause under recoveries	**---**	24.0
Cogeneration credit rider under recovery	**---**	1.4
Miscellaneous	**1.1**	1.5
Total Regulatory Assets	**$ 430.4**	$ 464.3
Regulatory Liabilities		
Accrued removal obligations, net	**$ 153.3**	$ 150.9
Fuel clause over recoveries	**73.0**	8.6
Miscellaneous	**6.8**	4.5
Total Regulatory Liabilities	**$ 233.1**	$ 164.0

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

Price Risk Management Assets and Liabilities

In accordance with FASB Interpretation ("FIN") No. 39 (As Amended), "Offsetting of Amounts Related to Certain Contracts – an interpretation of Accounting Principles Board ("APB") Opinion No. 10 and FASB Statement No. 105," fair value amounts recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the 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 $51.9 million and $48.2 million, respectively, at March 31, 2009, and non-current Price Risk Management assets and liabilities would be approximately $82.4 million and $42.7 million, respectively, at March 31, 2009. If these transactions with the same counterparty were presented on a gross basis in the Condensed Consolidated Balance Sheets, current Price Risk Management assets and liabilities would be approximately $51.8 million and $35.4 million, respectively, at December 31, 2008, and non-current Price Risk Management 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 noncontrolling interests in a subsidiary in connection with the adoption of SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements," as discussed in Note 2.

2. Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 160 which is intended to improve the relevance, comparability and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations. SFAS No. 160 amends Accounting Research Bulletin ("ARB") No. 51, "Consolidated Financial Statements," to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 also amends certain of ARB No. 51's consolidation procedures for consistency with the requirements of SFAS No. 141(R), "Business Combinations." SFAS No. 160 was effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The provisions of SFAS No. 160 are to be applied prospectively as of the beginning of the fiscal year in which it is initially adopted, except for the presentation and disclosure requirements, which are to be applied retrospectively for all periods presented. The Company adopted this new standard effective January 1, 2009. The adoption of this new standard changed the presentation of noncontrolling interests in the Company's consolidated financial statements for the Atoka joint venture.

In February 2008, the FASB issued FASB Staff Position ("FSP") No. 157-2, "Effective Date of FASB Statement No. 157," which deferred the effective date of SFAS No. 157, "Fair Value Measurements," for nonfinancial assets and liabilities measured on a nonrecurring basis to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. The provisions of this FSP should be applied prospectively. The Company adopted this new FSP effective January 1, 2009. The adoption of this new FSP did not impact the Company as the Company does not currently have any nonfinancial assets and liabilities measured on a nonrecurring basis.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities," which required enhanced disclosures about an entity's derivative and hedging activities and was intended to improve the transparency of financial reporting (see Note 4 for a further discussion).

In June 2008, the FASB issued FSP No. Emerging Issues Task Force ("EITF") 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities," which states that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share ("EPS") pursuant to the two-class method described in SFAS No. 128, "Earnings per Share." This FSP was effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2008. All prior-period EPS data presented should be adjusted retrospectively. The Company adopted this new FSP effective January 1, 2009. The adoption of this new FSP did not impact the Company’s EPS information as the Company already considered the restricted stock it had previously granted as a participating security and, therefore, included it in the EPS calculation.

In November 2008, the EITF reached a consensus and issued EITF Issue No. 08-6, “Equity Method Investment Accounting Considerations,” which applies to all investments accounted for under the equity method. EITF Issue No. 08-6 requires an entity: (i) to measure its equity method investment at cost in accordance with SFAS No. 141(R), (ii) to recognize other-than-temporary impairments of an equity method investment in accordance with APB Opinion No. 18, “The Equity Method of Accounting for Investments in Common Stock,” and (iii) to account for a share issuance by an investee as if the investor had sold a proportionate share of its investment with any gain or loss to the investor resulting from an investee’s share issuance being recognized in earnings. EITF Issue No. 08-6 was effective for fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years. The provisions of EITF Issue No. 08-6 are to be applied prospectively. The Company adopted this new EITF effective January 1, 2009. The adoption of this new EITF did not have a material impact on the Company’s consolidated financial position or results of operations.

In April 2009, the FASB issued FSP No. FAS 157-4, “Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,” which applies to all assets and liabilities within the scope of accounting pronouncements that require or permit fair value measurements, except as discussed in paragraphs 2 and 3 of SFAS No. 157. This FSP requires that in order to determine fair value, an entity should evaluate factors to determine whether there has been a significant decrease in the volume and level of activity for the asset or liability when compared with normal market activity for the asset or liability. If the entity concludes there has been a significant decrease, transactions or quoted prices may not be determinative of fair value and further analysis of the transactions or quoted prices would be needed. This FSP also reaffirmed that even if there has been a significant decrease as discussed above, fair value is the price to sell an asset or transfer a liability in an orderly transaction under current market conditions. Also, this FSP requires an entity to evaluate the circumstances to determine whether the transaction is orderly (i.e. not distressed or forced) based on the weight of the evidence obtained. In addition, an entity is expected to have sufficient information to conclude whether a transaction is orderly when it is party to the transaction. This FSP amends SFAS No. 157 to require that an entity disclose in its interim and annual periods the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, during the period. This FSP is effective for interim and annual reporting periods ending after June 15, 2009, and shall be applied prospectively. Early adoption of this FSP is permitted for periods ending after March 15, 2009 to the extent an entity also early adopts the FSP discussed below and the recently issued FSP related to other-than-temporary impairments. The Company adopted this new FSP effective April 1, 2009. The adoption of this new FSP is not expected to have a material impact on the Company’s consolidated financial position or results of operations.

In April 2009, the FASB issued FSP No. FAS 107-1 and APB Opinion No. 28-1, “Interim Disclosures about Fair Value of Financial Instruments,” which applies to all financial instruments within the scope of SFAS No. 107, “Disclosures about Fair Value of Financial Instruments,” and requires entities to include disclosures about the fair value of its financial instruments with the related carrying amount. An entity is also required to disclose the methods and significant assumptions used to estimate the fair value of financial instruments and shall describe changes in methods and significant assumptions, if any, during the period. This FSP is effective for interim periods ending after June 15, 2009. Early adoption of this FSP is permitted for periods ending after March 15, 2009 to the extent an entity also early adopts FAS 157-4 above and the recently issued FSP related to other-than-temporary impairments. The provisions of this FSP do not require disclosures for earlier periods presented for comparative purposes at initial adoption. The Company adopted this new FSP effective April 1, 2009. The adoption of this new FSP will require disclosures about the fair value of financial instruments for interim periods in the Company’s consolidated financial statements similar to what was reported in the Company’s 2008 Form 10-K.

3. Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157 which defined fair value, established a framework for measuring fair value in generally accepted accounting principles and established a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. SFAS No. 157 expanded disclosures about the use of fair value to measure assets and liabilities in interim and annual periods subsequent to initial recognition. The guidance in SFAS No. 157 applies to derivatives and other financial instruments measured at fair value under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities,” at initial recognition and in all subsequent periods. The Company adopted this standard effective January 1, 2008.

The following table is a summary of the Company's assets and liabilities that are measured at fair value on a recurring basis in accordance with SFAS No. 157.

(In millions)	**March 31, 2009**	**Level 1**	**Level 2**	**Level 3**
Assets				
Gross derivative assets	**$ 192.3**	$ 54.7	$ 32.0	$ 105.6
Gas imbalance assets	**1.5**	---	1.5	---
Total	**$ 193.8**	$ 54.7	$ 33.5	$ 105.6
Liabilities				
Gross derivative liabilities	**$ 139.6**	$ 45.2	$ 94.4	$ ---
Gas imbalance liabilities (A)	**6.7**	---	6.7	---
Total	**$ 146.3**	$ 45.2	$ 101.1	$ ---

(A) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of approximately $9.9 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 by the SFAS No. 157 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 March 31, 2009 and December 31, 2008.

(In millions)	**March 31, 2009**	December 31, 2008
Assets		
Gross derivative assets	**$ 192.3**	$ 243.7
Less: Amounts held in clearing broker accounts reflected in Other Current Assets	**58.0**	86.3
Less: Amounts offset under master netting agreements in accordance with FIN No. 39-1	**68.7**	65.4
Less: Collateral payments received from counterparties netted in accordance with FIN No. 39-1	**30.4**	58.1
Net Price Risk Management Assets	**$ 35.2**	$ 33.9
Liabilities		
Gross derivative liabilities	**$ 139.6**	$ 141.8
Less: Amounts held in clearing broker accounts reflected in Other Current Assets	**48.6**	70.3
Less: Amounts offset under master netting agreements in accordance with FIN No. 39-1	**68.9**	65.4
Less: Collateral payments to counterparties netted in accordance with FIN No. 39-1	**---**	---
Net Price Risk Management Liabilities	**$ 22.1**	$ 6.1

The following table is a summary of the Company's assets that are measured at fair value on a recurring basis in accordance with SFAS No. 157 using significant unobservable inputs (Level 3).

	Three Months Ended March 31,	
(In millions)	**2009**	2008
Derivative Assets		
Beginning balance	**$ 121.2**	$ 1.4
Total gains or losses (realized/unrealized)		
Included in earnings	**---**	---
Included in other comprehensive income	**(11.1)**	0.1
Purchases, sales, issuances and settlements, net	**(4.5)**	---
Transfers in and/or out of Level 3	**---**	---
Ending balance	**$ 105.6**	$ 1.5
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 March 31, 2009	**$ ---**	$ **---**

Gains and losses (realized and unrealized) included in earnings for the three months ended March 31, 2009 attributable to the change in unrealized gains or losses relating to assets held at March 31, 2009, if any, are reported in Operating Revenues.

The following information is provided regarding the estimated fair value of the Company's financial instruments, including derivative contracts related to the Company's price risk management activities, which have significantly changed since December 31, 2008.

	March 31, 2009		December 31, 2008	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value

Price Risk Management Liabilities				
Energy Derivative Contracts	**$ 22.1**	**$ 22.1**	$ 6.1	$ 6.1
Long-Term Debt				
Enogex Revolving Credit Facility	**$ 200.0**	**$ 200.0**	$ 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.

4. Disclosures about Derivative Instruments and Hedging Activities

In March 2008, the FASB issued SFAS No. 161 which required enhanced disclosures about an entity's derivative and hedging activities and was intended to improve the transparency of financial reporting. SFAS No. 161 applies to all entities. SFAS No. 161 applies to all derivative instruments, including bifurcated derivative instruments and related hedging items accounted for under SFAS No. 133 and its related interpretations. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133 with the intent to provide users of financial statements with an enhanced understanding of: (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The provisions of this standard do not require disclosures for earlier periods presented for comparative purposes at initial adoption. SFAS No. 161 was effective for fiscal years and interim periods beginning after November 15, 2008. The Company adopted this new standard effective January 1, 2009. The adoption of this new standard changed the disclosure related to derivative and hedging activities in the Company's consolidated financial statements.

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 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 under the provisions of SFAS No. 133. 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 subsidiary, Enogex Products LLC; (iii) electric power contracts by OG&E; and (iv) fuel procurement by OG&E.

In accordance with SFAS No. 133, the Company recognizes its non-exchange traded derivative instruments as Price Risk Management 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.

For OG&E, new business customers are required to provide a security deposit in the form of cash, a bond or irrevocable letter of credit that is refunded when the account is closed. New residential customers, whose outside credit scores indicate risk, are required to provide a security deposit that is refunded based on customer protection rules defined by the OCC and the APSC. The payment behavior of all existing customers is continuously monitored and, if the payment behavior indicates sufficient risk within the meaning of the applicable utility regulation, customers will be required to provide a security deposit.

For Enogex and OERI, credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. Enogex and OERI maintain 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 and the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty. Enogex and OERI also monitor the financial position of existing counterparties on an ongoing basis.

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 prescribed by SFAS No. 133. 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 prescribed by SFAS No. 133. 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 March 31, 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 March 31, 2009 covers the period from April 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 March 31, 2009 does not extend beyond the first quarter of 2010. At March 31, 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	**1.3**	Current
Short Financial Swaps/Futures (fixed)	NGLs	**1.0**	Non-Current
Total Short Financial Swaps/Futures (fixed)		**2.3**	
Purchased Financial Options	NGLs	**1.3**	Current
Purchased Financial Options	NGLs	**2.3**	Non-Current
Total Purchased Financial Options		**3.6**	
Long Financial Swaps/Futures (fixed)	Natural Gas	**11.4**	Current
Long Financial Swaps/Futures (fixed)	Natural Gas	**12.5**	Non-Current
Total Long Financial Swaps/Futures (fixed)		**23.9**	
Short Financial Swaps/Futures (fixed)	Natural Gas	**2.8**	Current
Short Financial Swaps/Futures (fixed)	Natural Gas	**0.7**	Non-Current
Total Short Financial Swaps/Futures (fixed)		**3.5**	
Long Financial Basis Swaps	Natural Gas	**1.8**	Current
Long Financial Basis Swaps	Natural Gas	**0.4**	Non-Current
Total Long Financial Basis Swaps		**2.2**	
Short Financial Basis Swaps	Natural Gas	**2.8**	Current
Short Financial Basis Swaps	Natural Gas	**0.6**	Non-Current
Total Short Financial Basis Swaps		**3.4**	

(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 March 31, 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 Under SFAS No. 133

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 marketing and trading activities.

At March 31, 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)**	**Maturity**
	(volumes in millions)		
Physical Purchases (B)	Natural Gas	**19.5**	Current
Physical Sales (B)	Natural Gas	**34.9**	Current
Physical Sales (B)	Natural Gas	**4.1**	Non-Current
Total Physical Sales		**39.0**	
Long Financial Swaps/Futures (fixed)	Natural Gas	**18.3**	Current
Long Financial Swaps/Futures (fixed)	Natural Gas	**0.9**	Non-Current
Total Long Financial Swaps/Futures (fixed)		**19.2**	
Short Financial Swaps/Futures (fixed)	Natural Gas	**21.1**	Current
Short Financial Swaps/Futures (fixed)	Natural Gas	**0.1**	Non-Current
Total Short Financial Swaps/Futures (fixed)		**21.2**	
Purchased Financial Options	Natural Gas	**18.3**	Current
Sold Financial Options	Natural Gas	**12.5**	Current
Long Financial Basis Swaps	Natural Gas	**11.9**	Current
Short Financial Basis Swaps	Natural Gas	**16.2**	Current

(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 March 31, 2009 are as follows:

		Asset Derivatives		Liability Derivatives	
Instrument	**Commodity**	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
(dollars in millions)					
Derivatives Designated as Hedging Instruments Under SFAS No. 133					
Financial Options	NGLs	Current PRM	**$ 20.1**	Current PRM	**$ ---**
		Non-Current PRM	**70.5**	Non-Current PRM	**---**
Financial Futures/Swaps	NGLs	Current PRM	**19.5**	Current PRM	**---**
		Non-Current PRM	**11.2**	Non-Current PRM	**---**
Financial Futures/Swaps	Natural Gas	Current PRM	**2.6**	Current PRM	**43.7**
		Non-Current PRM	**0.5**	Non-Current PRM	**42.5**
		Other Current Assets	**22.8**	Other Current Assets	**10.1**
Total Gross Derivatives Designated as Hedging Instruments Under SFAS No. 133			**$147.2**		**$ 96.3**
Derivatives Not Designated as Hedging Instruments Under SFAS No. 133					
Financial Futures/Swaps	Natural Gas	Current PRM	**$ 0.2**	Current PRM	**$ 0.5**
		Other Current Assets	**34.9**	Other Current Assets	**38.0**
Physical Purchases/Sales	Natural Gas	Current PRM	**8.7**	Current PRM	**4.2**
		Non-Current PRM	**1.0**	Non-Current PRM	**---**
Financial Options	Natural Gas	Other Current Assets	**0.3**	Other Current Assets	**0.6**
Total Gross Derivatives Not Designated as Hedging Instruments Under SFAS No. 133			**$ 45.1**		**$ 43.3**
Total Gross Derivatives (A)			**$192.3**		**$139.6**

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

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 March 31, 2009, the Company would have been required to post approximately $14.8 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 March 31, 2009.

The following table presents the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the three months ended March 31, 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 SFAS No. 133 Cash Flow Hedging Relationships					
NGLs Financial Options	**$ 55.7**	Operating Revenues	**$ 1.8**	Operating Revenues	**$ ---**
NGLs Financial Futures/Swaps	**30.7**	Operating Revenues	**5.5**	Operating Revenues	**---**
Natural Gas Financial Futures/Swaps	**(70.4)**	Operating Revenues	**1.9**	Operating Revenues	**---** (B)
Total	**$ 16.0**	**Total**	**$ 9.2**	**Total**	**$** ---

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at March 31, 2009 that is expected to be reclassified into earnings within the next 12 months is less than $0.1 million.

(B) The ineffective portion of these hedges is less than $0.1 million.

Derivatives Not Designated as Hedging Instruments Under SFAS No. 133	Location of Gain or Loss Recognized in Income on Derivative	Amount of Gain or Loss Recognized in Income of Derivative
Natural Gas Physical Purchases/Sales Options	Operating Revenues	**$ (8.2)**
Natural Gas Financial Futures/Swaps	Operating Revenues	**6.6**
NGLs Financial Futures/Swaps	Operating Revenues	**(0.2)**
Total		**$ (1.8)**

5. 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 $1.4 million pre-tax ($0.8 million after tax, or $0.01 per basic and diluted share) and approximately $1.1 million pre-tax ($0.7 million after tax, or $0.01 per basic and diluted share) during the three months ended March 31, 2009 and 2008, respectively, related to the Company's share-based payments.

During the three months ended March 31, 2009, the Company awarded 299,453 performance units based on total shareholder return and 99,818 performance units based on earnings per share with a grant date fair value under SFAS No. 123 (Revised), "Share-Based Payment," of $23.93 and $20.02, respectively, to certain employees of the Company and its subsidiaries. Also, during the three months ended March 31, 2009, the Company converted 171,670 performance units based on a payout ratio of 135.31 percent of the target number of performance units granted in February 2006.

The Company issues new shares to satisfy stock option exercises and payouts of earned performance units. During the three months ended March 31, 2009, there were 162,748 shares of new common stock issued pursuant to the Company's Plans related to payouts of earned performance units. There were no exercised stock options during the three months ended March 31, 2009; however, the Company received approximately $0.2 million during the three months ended March 31, 2008 related to exercised stock options.

6. Accumulated Other Comprehensive Income (Loss)

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

(In millions)	**March 31, 2009**	December 31, 2008
Defined benefit pension plan and restoration of retirement income plan:		
Net loss, net of tax (($70.3) and ($71.6) pre-tax, respectively)	**$ (43.0)**	$ (43.8)
Prior service cost, net of tax (($0.7) and ($0.8) pre-tax, respectively)	**(0.5)**	(0.5)
Defined benefit postretirement plans:		
Net loss, net of tax (($8.6) and ($8.6) pre-tax, respectively)	**(5.2)**	(5.3)
Net transition obligation, net of tax (($0.8) and ($0.8) pre-tax, respectively)	**(0.5)**	(0.5)
Prior service cost, net of tax (($0.3) and ($0.3) pre-tax, respectively)	**(0.2)**	(0.2)
Deferred hedging gains, net of tax ($16.0 and $62.4 pre-tax, respectively)	**9.8**	38.1
Deferred hedging losses on interest rate swaps, net of tax (($2.2) and ($2.4) pre-tax, respectively)	**(1.4)**	(1.5)
Total accumulated other comprehensive loss, net of tax	**$ (41.0)**	$ (13.7)

At both March 31, 2009 and December 31, 2008, there was no accumulated other comprehensive income related to the Company's noncontrolling interest in the Atoka joint venture.

7. Income Taxes

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal 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. This ratable amortization results in a larger percentage reconciling item related to these credits during the first quarter when the Company historically experiences decreased book income. In addition, OG&E earns both Federal and Oklahoma state tax credits associated with the production from its 120 megawatt ("MW") wind farm in northwestern Oklahoma that further reduce the Company's effective tax rate.

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

8. Common 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 1,240,072 shares of common stock under the DRIP/DSPP during the three months ended March 31, 2009 and received proceeds of approximately $29.2 million. The Company may, from time to time, issue additional shares under its DRIP/DSPP to fund capital requirements or working capital needs. At March 31, 2009, there were 3,759,928 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 March 31,	
(In millions)	**2009**	2008
Average Common Shares Outstanding		
Basic average common shares outstanding	**94.7**	91.9
Effect of dilutive securities:		
Employee stock options and unvested stock grants	**---**	0.2
Contingently issuable shares (performance units)	**0.6**	0.4
Diluted average common shares outstanding	**95.3**	92.5
Anti-dilutive shares excluded from EPS calculation	**---**	---

9. Long-Term Debt

At March 31, 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**
0.70% - 1.00%	Garfield Industrial Authority, January 1, 2025	**$ 47.0**
0.54% - 0.74%	Muskogee Industrial Authority, January 1, 2025	**32.4**

0.55% - 0.75%	Muskogee Industrial Authority, June 1, 2027		**55.9**
Total (redeemable during next 12 months)		**$**	**135.3**

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 except as discussed below. 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.

In September 2008, OG&E received a request for repayment of approximately $0.1 million of principal related to a portion of OG&E's Muskogee Industrial Authority variable-rate bonds, due June 1, 2027. In September 2008, approximately $0.1 million of principal and accrued interest were paid to the bondholder.

10. 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 $351.5 million and $298.0 million at March 31, 2009 and December 31, 2008, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at March 31, 2009.

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

Entity	Aggregate Commitment	Amount Outstanding (A)	Weighted-Average Interest Rate	Maturity
OGE Energy (B)	$ 596.0	$ 298.0	0.80% (D)	December 6, 2012
OG&E (C)	389.0	53.5	0.68% (D)	December 6, 2012
Enogex (E)	250.0	200.0	0.86% (D)	March 31, 2013
	1,235.0	551.5	0.81%	
Cash	146.4	N/A	N/A	N/A
Total	$ 1,381.4	$ 551.5	0.81%	

(A) Includes direct borrowings and letters of credit at March 31, 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 March 31, 2009, there was approximately $298.0 million in outstanding borrowings under this revolving credit agreement. There were no outstanding commercial paper borrowings at March 31, 2009.

(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 March 31, 2009, there was approximately $53.5 million in outstanding borrowings under this revolving credit agreement and approximately $0.3 million supporting letters of credit. There were no outstanding commercial paper borrowings at March 31, 2009.

(D) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements.

(E) This bank facility is available to provide revolving credit borrowings for Enogex. At March 31, 2009, there was approximately $200.0 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 has been adversely impacted by the market turmoil that began in September 2008. Accordingly, in order to ensure the availability of funds, OGE Energy and OG&E utilized borrowings under their revolving credit agreements, which generally bear a higher interest rate and a minimum 30-day maturity compared to commercial paper, which has historically been available at lower interest rates and on a daily basis. However, in late 2008, OGE Energy's and OG&E's revolving credit borrowings had a lower interest rate than commercial paper due to disruptions in the credit markets. In December 2008, OG&E repaid the outstanding borrowings under its revolving credit agreement with a portion of the proceeds received from the issuance of long-term debt in December. By March 2009, overnight to two-week commercial paper interest rates had decreased and, as a result, in April 2009 OG&E repaid its outstanding borrowings under its revolving credit agreement and began utilizing the commercial paper market. OGE Energy expects to gradually repay its outstanding borrowings under its revolving credit agreement. Also, OGE Energy began utilizing the commercial paper market in April 2009.

In addition to general market conditions, OGE Energy's and OG&E's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade. 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 marketing operations.

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

11. Retirement Plans and Postretirement Benefit Plans

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R," which required an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity. The requirement to initially recognize the funded status of the defined benefit postretirement plan and the disclosure requirements were effective for the year ended December 31, 2006 for the Company. Also, as part of SFAS No. 158, an employer is required to measure the fair value of the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. The requirement to measure plan assets and benefit obligations at fair value in accordance with SFAS No. 157 as of the date of the employer's fiscal year-end statement of financial position was effective for fiscal years ending after December 15, 2008. The Company adopted this additional provision of SFAS No. 158 effective December 31, 2008 which had no impact to the Company as its measurement date and its fiscal year-end statement of financial position were the same.

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		Restoration of Retirement Income Plan	
	Three Months Ended March 31,		**Three Months Ended March 31,**	
(In millions)	**2009**	2008	**2009**	2008
Service cost	**$ 4.5**	$ 4.7	**$ 0.2**	$ 0.1
Interest cost	**7.8**	7.8	**0.1**	0.1
Return on plan assets	**(8.2)**	(10.9)	**---**	---
Amortization of net loss	**5.9**	2.3	**0.1**	0.1
Amortization of unrecognized prior service cost	**0.2**	0.3	**0.1**	0.2
Net periodic benefit cost (A)	**$ 10.2**	$ 4.2	**$ 0.5**	$ 0.5

	Postretirement Benefit Plans	
	Three Months Ended March 31,	
(In millions)	**2009**	2008
Service cost	**$ 0.8**	$ 0.9
Interest cost	**3.5**	3.3
Return on plan assets	**(1.6)**	(1.6)
Amortization of transition obligation	**0.7**	0.7
Amortization of net loss	**1.2**	1.0
Amortization of unrecognized prior service cost	**0.3**	0.5
Net periodic benefit cost	**$ 4.9**	$ 4.8

(A) In addition to the $10.7 million and $4.7 million in SFAS No. 87, "Employers' Accounting for Pensions," net periodic benefit cost recognized during the three months ended March 31, 2009 and 2008, respectively, OG&E also recognized a gain of approximately $1.1 million and an expense of approximately $2.5 million, respectively, to maintain the allowable amount to be recovered for pension expense identified as Deferred Pension Plan Expenses (see Note 1).

Pension Plan Funding

The Company previously disclosed in its 2008 Form 10-K that it may contribute up to $50 million to its pension plan during 2009. In April 2009, the Company contributed approximately $20 million to its pension plan and currently expects to contribute an additional $30 million to its pension plan during the remainder of 2009. Any expected contributions to the pension plan during 2009 would be discretionary contributions, anticipated to be in the form of cash, and are not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

12. Report of Business Segments

The Company's business is divided into four segments for financial reporting purposes. These segments are as follows: (i) electric utility, which is engaged in the generation, transmission, distribution and sale of electric energy, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. Other Operations primarily included 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 months ended March 31, 2009 and 2008.

Three Months Ended March 31, 2009 *(In millions)*	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	**$ 336.7**	**$ 108.3**	**$ 138.5**	**$ 192.3**	**$ ---**	**$ (169.2)**	**$ 606.6**
Cost of goods sold	**171.0**	**66.2**	**96.1**	**187.8**	**---**	**(167.9)**	**353.2**
Gross margin on revenues	**165.7**	**42.1**	**42.4**	**4.5**	**---**	**(1.3)**	**253.4**
Other operation and maintenance	**85.3**	**9.9**	**23.1**	**2.6**	**(3.3)**	**(1.1)**	**116.5**
Depreciation and amortization	**45.5**	**4.7**	**10.1**	**---**	**2.3**	**---**	**62.6**
Taxes other than income	**16.1**	**3.6**	**1.3**	**0.2**	**1.1**	**---**	**22.3**
Operating income (loss)	**$ 18.8**	**$ 23.9**	**$ 7.9**	**$ 1.7**	**$ (0.1)**	**$ (0.2)**	**$ 52.0**
Total assets	**$ 4,963.2**	**$ 1,348.0**	**$ 846.0**	**$ 176.8**	**$ 2,461.6**	**$ (3,188.1)**	**$ 6,607.5**

Three Months Ended March 31, 2008 *(In millions)*	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$ 386.4	$ 156.9	$ 256.8	$ 476.9	$ ---	$ (282.3)	$ 994.7
Cost of goods sold	240.6	122.7	195.6	471.4	---	(281.5)	748.8
Gross margin on revenues	145.8	34.2	61.2	5.5	---	(0.8)	245.9
Other operation and maintenance (A)	94.3	11.9	20.9	2.8	(3.2)	(1.5)	125.2
Depreciation and amortization	36.3	4.1	8.3	---	2.0	---	50.7
Taxes other than income	15.9	3.5	1.1	0.2	1.2	---	21.9
Operating income (loss)	$ (0.7)	$ 14.7	$ 30.9	$ 2.5	$ ---	$ 0.7	$ 48.1
Total assets	$ 3,897.4	$ 1,107.2	$ 597.5	$ 247.8	$ 2,011.1	$ (2,563.7)	$ 5,297.3

(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 pre-tax 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.

13. Commitments and Contingencies

Except as set forth below and in Note 14, 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.

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 Case

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. 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. Briefing on the Tenth Circuit Court appeals was completed by Grynberg and defendants and oral arguments were made to the Tenth Circuit Court on September 25, 2008. 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. The Company continues to vigorously defend this action and is optimistic that with the affirmation of the ruling in the defendants' favor by the Tenth Circuit Court this case will end, or will ultimately be upheld in any further appeals; however the Company is unable to predict with certainty the timing and outcome of a further appeal nor estimate the amount or range of potential loss to the Company if the outcome of the appeal is unfavorable.

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 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 on March 26, 2009. The administrative law judge ("ALJ") took this matter under advisement. OG&E believes that this case is without merit.

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. Various petitions and appeals related to this decision were made, including a petition from the Utility Air Regulatory Group ("UARG"). On February 6, 2009, the EPA filed a motion to dismiss their earlier request for the U.S. Supreme Court to review the February 8, 2008 decision. Also, on February 23, 2009, the U.S. Supreme Court denied the UARG petition. Therefore, the EPA has stated that it intends to draft mercury rules under the Federal Clean Air Act. Any costs associated with future mercury regulations are uncertain at this time but are expected to be significant. 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.

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. On March 10, 2009, the EPA proposed 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 would 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 outcome of this regulation is uncertain at this time.

Compliance with the proposed greenhouse gas regulation could result in significant expenditures by the Company and a significant increase in its cost of conducting business.

On April 17, 2009, the EPA issued a proposed endangerment 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 finding now enters the public comment period, which is the next step in the deliberative process the EPA must undertake before issuing final findings. Before taking any steps to propose regulations to reduce greenhouse gases under the Federal Clean Air Act, the EPA would conduct a regulatory process and consider stakeholder input. Notwithstanding this regulatory process, 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 regulations regarding the reduction of greenhouse gases could result in significant capital expenditures by the Company and a significant increase in its cost of conducting business.

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 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. As a result of the Supreme Court's decision, the need for additional capital and/or increased operating costs associated with cooling water intake structures at OG&E's generating facilities may be reduced.

Other

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

14. 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.

Pending Regulatory Matters

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. Several settlement conferences have been held in this matter. 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. If approved by the FERC, the settlement agreement will resolve all issues in the pending formula rate proceeding. 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. Comments on the settlement agreement were filed on May 4, 2009, and the settlement was supported by the FERC Staff and was not opposed by any other party in this matter. A group of non-parties, however, filed comments contesting the settlement agreement. OG&E expects to submit reply comments on May 11, 2009, asserting that the comments of non-parties should be disregarded and that the settlement agreement should be approved without modification or condition. If the judge in this matter deems the settlement agreement uncontested, OG&E and the SPP expect to make a joint filing with the FERC in mid-May 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. Assuming the interim implementation of the settlement agreement, OG&E expects to refund any over collections to its transmission customers beginning in 2010. It is not yet known what action the FERC will take on the pending settlement agreement.

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 ("Redbud Facility") 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, and a return on equity of 12.25 percent. In January 2009, the APSC Staff recommended a $12.0 million rate increase based on a 10.5 percent return on equity. The Arkansas Attorney General's consultant recommended a return on equity at the current authorized level of 10.0 percent and stated that his analysis identified at least $10.9 million in reductions to OG&E's rate increase request. 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. A hearing on the settlement agreement was held on April 8, 2009, at which time the settlement agreement was unopposed by all parties in this matter, and a public hearing was held on April 30, 2009. If the settlement agreement is approved by the APSC, new electric rates would likely be implemented on or before July 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. OG&E was also authorized to seek recovery in its pending rate case but was not guaranteed recovery. 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. This settlement includes recovery of these storm costs.

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. The case is expected to proceed through the first half of 2009. If an increase is approved by the OCC, new electric rates would likely be implemented in September 2009. A procedural schedule was established on April 29, 2009 with the hearing on OG&E's rate case scheduled to begin on July 22, 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. At the hearing on March 27, 2009, the ALJ recommended approval of the settlement agreement. OG&E expects to receive an order from the OCC in the second quarter of 2009, with a targeted implementation date for the program and rider early in the third quarter of 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 with a hearing scheduled to begin on August 13, 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 March 20, 2009, the OCC Staff filed testimony recommending approval of the amended security plan. On April 7, 2009 a settlement agreement was filed that incorporated OG&E's requested relief. At the hearing on April 9, 2009, the ALJ recommended approval of the settlement agreement. OG&E expects to receive an order from the OCC in the second quarter of 2009.

OG&E Proposed 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 future OU Spirit wind project in western Oklahoma ("OU Spirit"). OG&E will seek regulatory recovery from the OCC and plans to have this project in-service by the end of 2009 or early 2010. Capital expenditures associated with this project are expected to be approximately $260 million.

In connection with OU Spirit, in January 2008, OG&E filed with the Southwest Power Pool ("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. OG&E is working with the SPP to expedite the study process with a goal of executing a final or interim LGIA prior to the in-service date of OU Spirit.

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.

Southwest Power Pool 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 December 2011. OG&E's estimated cost for its portion of the transmission line is approximately $66 million.

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's portion of the line and substation improvements is estimated to cost approximately $127 million. OG&E intends to begin preliminary line routing and acquisition of rights-of-way in mid-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.

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 $75 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 $33 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 June 2013. The capital expenditures related to the Balanced Portfolio 3E projects are presented in the summary of capital expenditures for growth opportunities in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

OGE Energy and Electric Transmission America Joint Venture

In July 2008, OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture to construct high-capacity transmission line projects in western Oklahoma. The Company owns 50 percent of the joint venture. The joint venture is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. Work on the joint venture projects is scheduled to begin in late 2009 and is targeted for completion by the end of 2013. The joint venture 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 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 the joint venture's 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. The joint venture's initial projects will include 765 kilovolt 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 joint venture projects discussed above are presented in the summary of capital expenditures for growth opportunities in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

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 new zonal rates for the Section 311 interruptible transportation service are expected to become 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 the rate case and in the SOC filing and some additionally filed protests. Enogex has filed answers to the interventions and protests in both matters. The regulations provide that the FERC has 150 days to act on the rate filing but also permit the issuance of an order extending the time period for action.

National Legislative Initiatives

In February 2009, the President signed into law the American Recovery and Reinvestment Act of 2009. 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. While the Company has not made an application at this time for any of the incentives provided in this law, the Company is exploring the criteria, the need and the mechanisms for applying for various grants, tax credits or loan guarantees that pertain to these areas of direct interest.

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”) is a provider 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: (1) natural gas transportation and storage and (2) natural gas gathering and processing. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream, LLC joint venture (“Atoka”) through Enogex Atoka LLC, a wholly owned subsidiary of Enogex.

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 to construct high-capacity transmission line projects in western Oklahoma. The Company owns 50 percent of the joint venture. The joint venture is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. Work on the joint venture projects is scheduled to begin in late 2009 and is targeted for completion by the end of 2013. The joint venture 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 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 the joint venture's 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. The joint venture's 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.

Summary of Operating Results

Quarter Ended March 31, 2009 as Compared to Quarter Ended March 31, 2008

Net income attributable to OGE Energy was approximately $16.8 million, or $0.18 per diluted share, during the three months ended March 31, 2009, as compared to approximately $13.0 million, or $0.14 per diluted share, during the same period in 2008. The increase in net income attributable to OGE Energy of approximately $3.8 million, or $0.04 per diluted share, during the three months ended March 31, 2009 as compared to the same period in 2008 was primarily due to:

- net income at OG&E of approximately $1.3 million during the three months ended March 31, 2009 as compared to a net loss of approximately $11.3 million during the same period in 2008, which was an increase in net income of approximately $12.6 million, or $0.13 per diluted share of the Company's common stock, during the three months ended March 31, 2009 as compared to the same period in 2008 primarily due to a higher gross margin on revenues ("gross margin"), lower operation and maintenance expenses and a higher allowance for equity funds used during construction partially offset by higher depreciation and amortization expense, higher interest expense and a lower income tax benefit;
- net income at Enogex of approximately $15.4 million during the three months ended March 31, 2009 as compared to approximately $22.5 million during the same period in 2008, which was a decrease in net income of approximately $7.1 million, or $0.08 per diluted share of the Company's common stock, during the three months ended March 31, 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 interest expense and lower income tax expense;
- net loss at OGE Energy of approximately $0.8 million during the three months ended March 31, 2009 as compared to net income of approximately $0.1 million during the same period in 2008, which was a decrease in net income of approximately $0.9 million, or $0.01 per diluted share of the Company's common stock, during the three months ended March 31, 2009 as compared to the same period in 2008 primarily due to a lower income tax benefit partially offset by lower interest expense; and
- net income at OGE Energy Resources, Inc. ("OERI") of approximately $0.9 million during the three months ended March 31, 2009 as compared to approximately $1.7 million during the same period in 2008, which was a decrease in net income of approximately $0.8 million, or less than $0.01 per diluted share of the Company's common stock, during the three months ended March 31, 2009 as compared to the same period in 2008 primarily due to a lower gross margin.

Timing Items. Enogex's net income for the three months ended March 31, 2009 was approximately $15.4 million, which included a realized gain of approximately $3.3 million related to the March 2009 component of Enogex's operational storage hedges. This amount will be offset by approximately $1.5 million upon recognition of the May 2009 component of Enogex's operational storage hedges, which are currently deferred in Accumulated Other Comprehensive Income.

OERI's net income for the three months ended March 31, 2008 was approximately $1.7 million, which included a net loss of approximately $1.0 million resulting from recording hedges associated with various transportation contracts at market value on March 31, 2008. The offsetting gains from physical utilization of the transportation capacity were realized during the second and third quarters of 2008.

Recent Developments and Regulatory Matters

Changes in the Capital, Credit and Commodity Markets

As a result of volatile conditions in global capital markets, general liquidity in short-term credit markets has been constrained despite several pro-active intervention measures undertaken by the Federal Reserve, the Department of the Treasury, the United States Congress and the President of the United States. As explained in more detail below, OGE Energy and OG&E historically have maintained access to short-term liquidity through the commercial paper market and utilization of direct borrowings on certain committed credit agreements, although the ability to access the commercial paper market has been more limited in recent months. By March 2009, the commercial paper market became more accessible and, therefore, in April 2009 OGE Energy and OG&E began utilizing the commercial paper market.

The volatility in global capital markets has lead to a reduction in the current value of long-term investments held in OGE Energy's pension trust and postretirement benefit plan trusts. The decline in asset value for the plans, if it continues for any length of time, could require additional future funding requirements.

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 quarter 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 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 megawatt ("MW") natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma ("Redbud Facility") 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, and a return on equity of 12.25 percent. In January 2009, the APSC Staff recommended a $12.0 million rate increase based on a 10.5 percent return on equity. The Arkansas Attorney General's consultant recommended a return on equity at the current authorized level of 10.0 percent and stated that his analysis identified at least $10.9 million in reductions to OG&E's rate increase request. 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. A hearing on the settlement agreement was held on April 8, 2009, at which time the settlement agreement was unopposed by all parties in this matter, and a public hearing was held on April 30, 2009. If the settlement agreement is approved by the APSC, new electric rates would likely be implemented on or before July 2009.

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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. OG&E is working with the SPP to expedite the study process with a goal of executing a final or interim LGIA prior to the in-service date of OU Spirit.

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.

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The maximum rate for the new firm East Zone Section 311 transportation service was effective April 1, 2009. The new zonal rates for the Section 311 interruptible transportation service are expected to become 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 the rate case and in the SOC filing and some additionally filed protests. Enogex has filed answers to the interventions and protests in both matters. The regulations provide that the FERC has 150 days to act on the rate filing but also permit the issuance of an order extending the time period for action.

Southeastern Oklahoma / East Side Expansions

Enogex is in the process of expanding its gathering facilities in the Southeastern Oklahoma area and plans to add approximately four miles of 16-inch gathering pipe, approximately 2,600 horsepower of additional compression and 25 million cubic feet per day of additional treating facilities, all of which are expected to be in service by the fourth quarter of 2009. The capital expenditures associated with the additional pipe and treating facilities are expected to be approximately $11.6 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 lower half of the range primarily due to lower commodity prices in Enogex's business partially offset by lower interest expense. The key factors and assumptions underlying this guidance are risk-adjusted to determine the ranges described below. Therefore, the ranges by component may not add to the total. See "2009 Outlook" in the Company's Annual Report on Form 10-K for the year ended December 31, 2008 ("2008 Form 10-K") for a description of the key factors and assumptions underlying this guidance. Management will monitor its assumptions throughout the year and will seek to take appropriate actions to offset any adverse change in its assumptions.

(In millions, except per share data)	Dollars	Diluted EPS
OG&E	$ 177 - $ 191	$ 1.83 - $ 1.98
Enogex	$ 51 - $ 68	$ 0.53 - $ 0.70
Holding Company & OERI	$ (10) - $ (5)	$ (0.10) - $ (0.05)
Consolidated	$ 220 - $ 250	$ 2.30 - $ 2.60

Results of Operations

The following discussion and analysis presents factors that affected the Company's consolidated results of operations for the three months ended March 31, 2009 as compared to the same period in 2008 and the Company's consolidated financial position at March 31, 2009. Due to seasonal fluctuations and other factors, the operating results for the three months ended March 31, 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 March 31,	
(In millions, except per share data)	**2009**	2008
Operating income	**$52.0**	$48.1
Net income attributable to OGE Energy	**$16.8**	$13.0
Basic average common shares outstanding	**94.7**	91.9
Diluted average common shares outstanding	**95.3**	92.5
Basic earnings per average common share attributable to OGE Energy common shareholders	**$0.18**	$0.14
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$0.18**	$0.14
Dividends declared per share	**$0.3550**	$0.3475

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

Operating Income (Loss) by Business Segment

	Three Months Ended March 31,	
(In millions)	**2009**	2008
OG&E (Electric Utility)	**$ 18.8**	$ (0.7)
Enogex (Natural Gas Pipeline)		
Transportation and storage	**23.9**	14.7
Gathering and processing	**7.9**	30.9
OERI (Natural Gas Marketing)	**1.7**	2.5
Other Operations (A)	**(0.3)**	0.7
Consolidated operating income	**$ 52.0**	$ 48.1

(A) Other Operations primarily includes the operations of the holding company and consolidating eliminations.

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

OG&E (Electric Utility)

	Three Months Ended March 31,	
(Dollars in millions)	**2009**	2008
Operating revenues	**$ 336.7**	$ 386.4
Cost of goods sold	**171.0**	240.6
Gross margin on revenues	**165.7**	145.8
Other operation and maintenance	**85.3**	94.3
Depreciation and amortization	**45.5**	36.3
Taxes other than income	**16.1**	15.9
Operating income (loss)	**18.8**	(0.7)
Interest income	**0.5**	0.3
Allowance for equity funds used during construction	**1.3**	---
Other income	**4.6**	2.3
Other expense	**0.5**	0.7
Interest expense	**24.3**	19.5
Income tax benefit	**0.9**	7.0
Net income (loss)	**$ 1.3**	$ (11.3)
Operating revenues by classification		
Residential	**$ 136.3**	$ 146.4
Commercial	**79.4**	89.4
Industrial	**32.8**	46.6
Oilfield	**28.9**	32.6
Public authorities and street light	**31.5**	36.1
Sales for resale	**12.7**	15.3
Provision for rate refund	**(0.2)**	---
System sales revenues	**321.4**	366.4
Off-system sales revenues	**5.9**	12.3
Other	**9.4**	7.7
Total operating revenues	**$ 336.7**	$ 386.4
MWH (A) sales by classification (in millions)		
Residential	**2.0**	2.2
Commercial	**1.4**	1.4
Industrial	**0.9**	1.0
Oilfield	**0.7**	0.7
Public authorities and street light	**0.6**	0.6
Sales for resale	**0.3**	0.4
System sales	**5.9**	6.3
Off-system sales	**0.2**	0.2
Total sales	**6.1**	6.5
Number of customers	**771,909**	765,165
Average cost of energy per KWH (B) – cents		
Natural gas	**3.793**	7.598
Coal	**1.544**	1.074
Total fuel	**2.226**	3.118
Total fuel and purchased power	**2.575**	3.440
Degree days (C)		
Heating - Actual	**1,675**	1,814
Heating - Normal	**1,963**	1,982
Cooling - Actual	**23**	12
Cooling - Normal	**8**	9

(A) Megawatt-hour.

(B) Kilowatt-hour.

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

Quarter Ended March 31, 2009 as Compared to Quarter Ended March 31, 2008

Operating Income

OG&E's operating income increased approximately $19.5 million during the three months ended March 31, 2009 as compared to the same period in 2008 primarily due to a higher gross margin and lower operation and maintenance expenses partially offset by higher depreciation and amortization expense.

Gross Margin

Gross margin was approximately $165.7 million during the three months ended March 31, 2009 as compared to approximately $145.8 million during the same period in 2008, an increase of approximately $19.9 million, or 13.6 percent. The gross margin increased primarily due to:

- new revenues from the Redbud Facility rider and the storm cost recovery rider, which increased the gross margin by approximately $19.3 million;
- increased price variance due to sales and customer mix, which increased the gross margin by approximately $5.6 million;
- new customer growth in OG&E's service territory, which increased the gross margin by approximately $1.7 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 $1.7 million.

These increases in gross margin were partially offset by:

- milder weather in OG&E's service territory, resulting in an approximate eight percent decrease in heating degree days compared to the same period in 2008, which decreased the gross margin by approximately $5.9 million; and
- decreased demand and related revenues by non-residential customers in OG&E's service territory, which decreased the gross margin by approximately $2.0 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was approximately $130.4 million during the three months ended March 31, 2009 as compared to approximately $186.6 million during the same period in 2008, a decrease of approximately $56.2 million, or 30.1 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 $40.1 million during the three months ended March 31, 2009 as compared to approximately $53.8 million during the same period in 2008, a decrease of approximately $13.7 million, or 25.5 percent, primarily due to lower purchases within the SPP energy imbalance 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 $85.3 million during the three months ended March 31, 2009 as compared to approximately $94.3 million during the same period in 2008, a decrease of approximately $9.0 million, or 9.5 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 12 of Notes to Condensed Consolidated Financial Statements;
- a decrease of approximately $2.6 million in contract technical and construction services attributable to an overhaul at one of OG&E's power plants during the first quarter of 2008;

- a decrease of approximately $1.7 million in allocations from OGE Energy primarily due to lower professional services in the first quarter of 2009 as compared to the same period in 2008; and
- a decrease of approximately $0.9 million in professional services expense primarily due to lower legal expenses in the first quarter of 2009 as compared to the same period in 2008.

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

- an increase of approximately $2.0 million in salaries and wages expense primarily due to hiring additional employees to support OG&E's operations as well as salary increases in 2009;
- an increase of approximately $1.4 million due to increased bad debt expense;
- an increase of approximately $1.1 million in medical and dental expenses and an increase of approximately $0.9 million in pension expenses; and
- an increase of approximately $1.0 million due to increased spending on vegetation management.

Depreciation and amortization expense was approximately $45.5 million during the three months ended March 31, 2009 as compared to approximately $36.3 million during the same period in 2008, an increase of approximately $9.2 million, or 25.3 percent, primarily due to additional assets, including the Redbud Facility, being placed into service after the first quarter of 2008 and amortization of the Oklahoma storm costs that are currently recorded as a regulatory asset (see Note 1 of Notes to Condensed Consolidated Financial Statements).

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction ("AEFUDC") was approximately $1.3 million during the three months ended March 31, 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 that exceeded the average daily short-term borrowings.

Other Income. Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating income. Other income was approximately $4.6 million during the three months ended March 31, 2009 as compared to approximately $2.3 million during the same period in 2008, an increase of approximately $2.3 million, or 100.0 percent. Approximately $1.6 million of the increase in other income was due to more customers participating in the guaranteed flat bill program, along with milder weather in 2009, and approximately $0.9 million of the increase in other income related to the benefit associated with the tax gross-up of AEFUDC.

Interest Expense. Interest expense was approximately $24.3 million during the three months ended March 31, 2009 as compared to approximately $19.5 million during the same period in 2008, an increase of approximately $4.8 million, or 24.6 percent. The increase in interest expense was primarily due to an increase of approximately $9.6 million in interest expense related to the issuances of long-term debt in 2008. This increase in interest expense was partially offset by:

- 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; and
- a decrease of approximately $1.6 million related to interest on short-term debt primarily due to lower short-term borrowings due to the issuance of long-term debt by OG&E in 2008, of which a portion of the proceeds were used to repay outstanding short-term borrowings.

Income Tax Benefit. Income tax benefit was approximately $0.9 million during the three months ended March 31, 2009 as compared to approximately $7.0 million during the same period in 2008, a decrease of approximately $6.1 million, or 87.1 percent. The income tax benefit decreased primarily due to higher pre-tax income in the first quarter of 2009 as compared to a pre-tax loss during the same period in 2008 partially offset by an increase in Federal renewable energy credits and investment tax credits in the first 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 March 31, 2009 *(In millions)*	Transportation and Storage	Gathering and Processing	Eliminations	Total
Operating revenues	**$ 108.3**	**$ 138.5**	**$ (56.7)**	**$ 190.1**
Cost of goods sold	**66.2**	**96.1**	**(56.7)**	**105.6**
Gross margin on revenues	**42.1**	**42.4**	**---**	**84.5**
Other operation and maintenance	**9.9**	**23.1**	**---**	**33.0**
Depreciation and amortization	**4.7**	**10.1**	**---**	**14.8**
Taxes other than income	**3.6**	**1.3**	**---**	**4.9**
Operating income	**$ 23.9**	**$ 7.9**	**$ ---**	**$ 31.8**

Three Months Ended March 31, 2008 *(In millions)*	Transportation and Storage	Gathering and Processing	Eliminations	Total
Operating revenues	$ 156.9	$ 256.8	$ (147.0)	$ 266.7
Cost of goods sold	122.7	195.6	(147.0)	171.3
Gross margin on revenues	34.2	61.2	---	95.4
Other operation and maintenance	11.9	20.9	---	32.8
Depreciation and amortization	4.1	8.3	---	12.4
Taxes other than income	3.5	1.1	---	4.6
Operating income	$ 14.7	$ 30.9	$ ---	$ 45.6

Operating Data

Three Months Ended	**March 31,**	
	2009	2008
New well connects (includes wells behind central receipt points) (A)	**77**	85
New well connects (excludes wells behind central receipt points)	**40**	39
Gathered volumes – TBtu/d (B)	**1.24**	1.07
Incremental transportation volumes – TBtu/d	**0.42**	0.40
Total throughput volumes – TBtu/d	**1.66**	1.47
Natural gas processed – TBtu/d	**0.64**	0.62
Natural gas liquids sold (keep-whole) – million gallons	**21**	53
Natural gas liquids sold (purchased for resale) – million gallons	**70**	40
Natural gas liquids sold (percent-of-liquids) – million gallons	**8**	5
Total natural gas liquids sold – million gallons	**99**	98
Average net sales price per gallon	**$ 0.625**	$ 1.354
Estimated realized keep-whole spreads (C)	**$ 2.85**	$ 7.03

(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 NGL 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 NGL and the Inside FERC monthly index posting for Panhandle Eastern Pipe Line Co., Texas, Oklahoma, for the forward month contract for natural gas prices.

Quarter Ended March 31, 2009 as Compared to Quarter Ended March 31, 2008

Operating Income

Enogex's operating income decreased approximately $13.8 million during the three months ended March 31, 2009 as compared to the same period in 2008 primarily due to a lower gross margin in the gathering and processing business and higher depreciation and amortization expense, which was only partially offset by a higher gross margin in the transportation and storage business.

Gross Margin

Enogex's consolidated gross margin decreased approximately $10.9 million during the three months ended March 31, 2009 as compared to the same period in 2008. The decrease resulted from an $18.8 million lower gross margin in the gathering and processing business partially offset by a $7.9 million higher gross margin in the transportation and storage business.

The transportation and storage business contributed approximately $42.1 million of Enogex's consolidated gross margin during the three months ended March 31, 2009 as compared to approximately $34.2 million during the same period in 2008, an increase of approximately $7.9 million, or 23.1 percent. The transportation operations contributed approximately $34.2 million of Enogex's consolidated gross margin during the three months ended March 31, 2009 as compared to approximately $25.7 million during the same period in 2008. The storage operations contributed approximately $7.9 million of Enogex's consolidated gross margin during the three months ended March 31, 2009 as compared to approximately $8.5 million during the same period in 2008. The transportation and storage gross margin increased primarily due to:

- higher gross margins on realized operational storage hedges during the three months ended March 31, 2009 as compared to the same period in 2008, which increased the gross margin by approximately $4.7 million;
- a decreased imbalance liability, net of fuel recoveries and natural gas length positions, associated with the transportation operations during the three months ended March 31, 2009, which increased the gross margin by approximately $3.3 million;
- increased crosshaul revenues due to moving excess natural gas to the eastern U.S. markets as well as increased rates as a result of shippers bidding up rates to move natural gas on Enogex's pipeline system during the three months ended March 31, 2009, which increased the gross margin by approximately $3.0 million;
- a decrease in Enogex's over-recovered position under its FERC-approved fuel tracker in the East zone during the three months ended March 31, 2009 while during the same period in 2008 both the East and West zones were in an under-recovered position, which increased the gross margin by approximately $1.4 million;
- higher gross margins on commodity and interruptible fees resulting from increased activity from several customers during the three months ended March 31, 2009 as compared to the same period in 2008, which increased the gross margin by approximately $1.4 million; and
- higher low and high pressure revenues as a result of an approximate 28.7 percent volume increase primarily due to several new projects which began production in 2008, which increased the gross margin by approximately $1.1 million.

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

- a lower of cost or market adjustment related to natural gas inventories during the three months ended March 31, 2009 with no corresponding adjustment during the same period in 2008, which decreased the gross margin by approximately $5.8 million; and

- a decrease in demand fees associated with the transportation operations as the result of several customers utilizing crosshaul contracts rather than demand fee contracts during the three months ended March 31, 2009 due to the delay of third party downstream capacity being placed into service, which decreased the gross margin by approximately $1.5 million.

The gathering and processing business (which for these purposes includes all of the Atoka joint venture even though Enogex only owns a 50 percent interest in Atoka), contributed approximately $42.4 million of Enogex's consolidated gross margin during the three months ended March 31, 2009 as compared to approximately $61.2 million during the same period in 2008, a decrease of approximately $18.8 million, or 30.7 percent. The gathering operations contributed approximately $24.2 million of Enogex's consolidated gross margin during the three months ended March 31, 2009 as compared to approximately $18.9 million during the same period in 2008. The processing operations contributed approximately $18.2 million of

Enogex's consolidated gross margin during the three months ended March 31, 2009 as compared to approximately $42.3 million during the same period in 2008. The gathering and processing gross margin decreased primarily due to:

- a decrease in keep-whole margins associated with the processing operations during the three months ended March 31, 2009 as compared to the same period in 2008 primarily due to an approximate 60.3 percent decrease in keep-whole volumes from a shift to percent-of-liquids processing contracts, several processing plants being in ethane rejection for the beginning of the first quarter in 2009 compared to being in ethane recovery during the first quarter of 2008 and lower commodity spreads during the three months ended March 31, 2009, which decreased the gross margin by approximately $22.1 million;
- a decrease in the condensate margin associated with the processing operations due to an approximate 65.3 percent decrease in natural gas prices partially offset by an approximate 14.5 percent increase in volumes during the three months ended March 31, 2009 as compared to the same period in 2008, which decreased the gross margin by approximately $4.7 million;
- a decrease in the percent-of-liquids gross margin associated with the processing operations, including Atoka, due to an approximate 59.2 percent decrease in NGLs pricing during the three months ended March 31, 2009 partially offset by an approximate 81.1 percent increase in volumes retained by Enogex, which decreased the gross margin by approximately $2.0 million; and
- decreased sales of residue gas, condensate and additional retained NGLs associated with the processing operations of the Atoka joint venture as the result of a decline in NGLs prices and an increase in the costs associated with a certain third-party processing agreement due to an increase in volumes being processed partially offset by an increase in the total production volumes, which decreased the gross margin by approximately $1.8 million.

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

- higher compression and dehydration fees associated with the gathering operations resulting from several projects, including Atoka, which increased the gross margin by approximately $2.5 million;
- increased low pressure gathering fees associated with several projects, including Atoka, which increased the gross margin by approximately $1.1 million;
- a decreased imbalance liability, net of fuel recoveries and natural gas length positions during the three months ended March 31, 2009, which increased the gross margin by approximately $1.0 million; and
- unrealized gains resulting from economic hedges recorded at market value at March 31, 2009 as compared to March 31, 2008.

Operating Expenses

The aggregate of other operation and maintenance expenses, depreciation and amortization expense and taxes other than income was approximately $2.9 million higher during the three months ended March 31, 2009 as compared to the same period in 2008. The variance in depreciation and amortization expense on both a consolidated basis and by segment reflects differing levels of depreciable plant in service. The $0.2 million increase in other operation and maintenance expenses on a consolidated basis was primarily due to individually insignificant increases partially offset by a decrease in expenses for non-capitalized projects as a result of efforts to reduce operation and maintenance expenses during 2009.

Specifically, by segment, other operation and maintenance expenses for the transportation and storage business were approximately $2.0 million, or 16.8 percent, lower during the three months March 31, 2009 as compared to the same period in 2008 primarily due to lower contract professional, technical services and materials and supplies expense of approximately $2.9 million due to lower expenses on line remediation and non-capitalized projects during the three months ended March 31, 2009.

Other operation and maintenance expenses for the gathering and processing business were approximately $2.2 million, or 10.5 percent, higher during the three months ended March 31, 2009 as compared to the same period in 2008 primarily due to higher contract professional, technical services and materials and supplies expense of approximately $2.1 million due to higher expenses on line remediation and non-capitalized pipeline integrity projects during the three months ended March 31, 2009.

Enogex Consolidated Information

Interest Income. Enogex's consolidated interest income was approximately $0.1 million during the three months ended March 31, 2009 as compared to approximately $1.3 million during the same period in 2008, a decrease of approximately $1.2 million, or 92.3 percent. The decrease was 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 $5.9 million during the three months ended March 31, 2009 as compared to approximately $8.1 million during the same period in 2008, a decrease of approximately $2.2 million, or 27.2 percent, primarily due to an increase in the amount of construction expenditures eligible for interest capitalization during the three months ended March 31, 2009.

Income Tax Expense. Enogex's consolidated income tax expense was approximately $9.7 million during the three months ended March 31, 2009 as compared to approximately $14.7 million during the same period in 2008, a decrease of approximately $5.0 million, or 34.0 percent, primarily due to lower pre-tax income in the first quarter of 2009 as compared to the same period in 2008.

Timing Items. Enogex's net income for the three months ended March 31, 2009 was approximately $15.4 million, which included a realized gain of approximately $3.3 million related to the March 2009 component of Enogex's operational storage hedges. This amount will be offset by approximately $1.5 million upon recognition of the May 2009 component of Enogex's operational storage hedges, which are currently deferred in Accumulated Other Comprehensive Income.

OERI (Natural Gas Marketing)

	Three Months Ended March 31,			
	2009		2008	
(In millions)				
Operating revenues	**$**	**192.3**	$	476.9
Cost of goods sold		**187.8**		471.4
Gross margin on revenues		**4.5**		5.5
Other operation and maintenance		**2.6**		2.8
Taxes other than income		**0.2**		0.2
Operating income	**$**	**1.7**	$	2.5

Quarter Ended March 31, 2009 as Compared to Quarter Ended March 31, 2008

Operating Income

OERI's operating income decreased approximately $0.8 million during the three months ended March 31, 2009 as compared to the same period in 2008 primarily due to a lower gross margin.

Gross Margin

Gross margin was approximately $4.5 million during the three months ended March 31, 2009 as compared to approximately $5.5 million during the same period in 2008, a decrease of approximately $1.0 million, or 18.2 percent. The gross margin decreased primarily due to lower sales on withdrawals of natural gas from storage due to reduced capacity and lower prices, which decreased the gross margin by approximately $4.2 million. This decrease was partially offset by:

- decreased losses on economic hedges associated with various transportation contracts from recording these hedges at market value on March 31, 2009 as compared to recording these hedges at market value on March 31, 2008, which increased the gross margin by approximately $2.1 million; and
- higher realized gains associated with various transportation contracts during the three months ended March 31, 2009 as compared to the same period in 2008, which increased the gross margin by approximately $0.9 million.

Additional Information

Timing Items. OERI's net income for the three months ended March 31, 2008 was approximately $1.7 million, which included a net loss of approximately $1.0 million resulting from recording economic hedges associated with various transportation contracts at market value on March 31, 2008. The offsetting gains from physical utilization of the transportation capacity were realized during the second and third quarters of 2008.

Enogex's Non-GAAP Financial Measures

Enogex has included in this Form 10-Q the non-GAAP financial measure EBITDA. Enogex defines EBITDA as net income 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.

The economic substance behind the use of EBITDA is to measure the ability of Enogex's assets to generate cash sufficient to pay interest costs, support indebtedness and pay dividends to OGE Energy.

Enogex provides a reconciliation of EBITDA to its most directly comparable financial measures as calculated and presented in accordance with generally accepted accounting principles ("GAAP"). The GAAP measures most directly comparable to EBITDA are net cash provided from operating activities and net income. The non-GAAP financial measure of EBITDA should not be considered as an alternative to GAAP net cash provided from operating activities and GAAP net income. 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 net cash provided from operating activities and is defined differently by different companies in Enogex's industry, Enogex's definition of EBITDA may not be comparable to similarly titled measures of other companies.

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

Reconciliation of EBITDA to net cash provided from operating activities

	Three Months Ended

(In millions)	**March 31, 2009**	2008
Net cash (used in) provided from operating activities	**$ (8.6)**	$ 18.5
Interest expense, net	**5.8**	6.8
Changes in operating working capital which provided (used) cash:		
Accounts receivable	**(6.5)**	7.2
Accounts payable	**51.2**	16.9
Other, including changes in noncurrent assets and liabilities	**3.8**	7.0
EBITDA	**$ 45.7**	$ 56.4

Reconciliation of EBITDA to net income

	Three Months Ended March 31,			
(In millions)	**2009**		2008	
Net income attributable to Enogex LLC	**$**	**15.4**	$	22.5
Add:				
Interest expense, net		**5.8**		6.8
Income tax expense		**9.7**		14.7
Depreciation and amortization		**14.8**		12.4
EBITDA	**$**	**45.7**	$	56.4

Financial Condition

The balance of Cash and Cash Equivalents was approximately $146.4 million and $174.4 million at March 31, 2009 and December 31, 2008, respectively, a decrease of approximately $28.0 million, or 16.1 percent. See "Cash Flows" for a discussion of the changes in Cash and Cash Equivalents.

The balance of Accounts Receivable was approximately $239.4 million and $288.1 million at March 31, 2009 and December 31, 2008, respectively, a decrease of approximately $48.7 million, or 16.9 percent, primarily due to a decrease in OG&E's billings to its customers reflecting milder weather in March 2009 as compared to December 2008 and a decrease in natural gas prices and volumes at Enogex and OERI.

The balance of Fuel Inventories was approximately $94.6 million and $88.7 million at March 31, 2009 and December 31, 2008, respectively, an increase of approximately $5.9 million, or 6.7 percent, primarily due to an increased balance in coal inventory in anticipation of higher usage in the summer months at OG&E partially offset by a decrease in natural gas inventory pertaining to a certain storage contract at OERI resulting from a withdrawal of natural gas from storage at the end of the contract term and a reduction in natural gas inventory due to the recognition of a lower of cost or market adjustment at Enogex.

The balance of Fuel Clause Under Recoveries was approximately $24.0 million at December 31, 2008 with no balance at March 31, 2009, primarily due to the fact that the amount billed to retail customers at March 31, 2009 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 $478.8 million and $399.0 million at March 31, 2009 and December 31, 2008, respectively, an increase of approximately $79.8 million, or 20.0 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.

The balance of Short-Term Debt was approximately $351.5 million and $298.0 million at March 31, 2009 and December 31, 2008, respectively, an increase of approximately $53.5 million, or 18.0 percent, primarily due to increased borrowings under OG&E's revolving credit agreement to fund new construction projects associated with OU Spirit and the extra high voltage transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma being constructed by OG&E.

The balance of Accounts Payable was approximately $219.7 million and $279.7 million at March 31, 2009 and December 31, 2008, respectively, a decrease of approximately $60.0 million, or 21.5 percent, primarily due to payments made during the first quarter of 2009 for Enogex projects accrued at December 31, 2008, a decrease in natural gas volumes and prices at Enogex and OERI and less purchased power at OG&E.

The balance of Accrued Taxes was approximately $0.9 million and $26.8 million at March 31, 2009 and December 31, 2008, respectively, a decrease of approximately $25.9 million, or 96.6 percent, primarily due to ad valorem tax payments in the first quarter of 2009 and an increase in income tax benefit accruals related to the Federal tax benefit on the portion of the estimated net operating loss expected to be recognized through carryback adjustments to the 2007 tax year.

The balance of Accrued Interest was approximately $32.5 million and $48.7 million at March 31, 2009 and December 31, 2008, respectively, a decrease of approximately $16.2 million, or 33.3 percent, primarily due to interest payments on long-term debt in the first quarter of 2009 partially offset by additional interest accrued on long-term debt.

The balance of Accrued Compensation was approximately $29.2 million and $45.2 million at March 31, 2009 and December 31, 2008, respectively, a decrease of approximately $16.0 million, or 35.4 percent, primarily due to the annual payment for incentive compensation made in the first quarter of 2009.

The balance of Long-Term Debt Due Within One Year was approximately $400.7 million at March 31, 2009 with no balance at December 31, 2008, primarily due to the classification of Enogex's $400.0 million medium-term senior notes as a current liability as they mature in January 2010.

The balance of Fuel Clause Over Recoveries was approximately $73.0 million and $8.6 million at March 31, 2009 and December 31, 2008, respectively, an increase of approximately $64.4 million, primarily due to the fact that the amount billed to retail customers at March 31, 2009 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 Other Current Liabilities was approximately $37.4 million and $62.2 million at March 31, 2009 and December 31, 2008, respectively, a decrease of approximately $24.8 million, or 39.9 percent, primarily due to a reduction in the liability for a certain 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 and a decrease in the liability for the off-system sales credit at OG&E due to lower sales in the energy imbalance market.

The balance of Long-Term Debt was approximately $1.8 billion and $2.2 billion at March 31, 2009 and December 31, 2008, respectively, a decrease of approximately $0.4 billion, or 18.2 percent, primarily due to the classification of Enogex's $400.0 million medium-term senior notes as a current liability as they mature in January 2010 partially offset by increased borrowings of approximately $80.0 million during the first quarter of 2009 under Enogex's revolving credit agreement.

The balance of Accumulated Other Comprehensive Loss was approximately $41.0 million and $13.7 million at March 31, 2009 and December 31, 2008, respectively, an increase of approximately $27.3 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 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 March 31, 2009, the Company had approximately $146.4 million of cash and cash equivalents. At March 31, 2009, the Company had approximately $683.2 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 marketing and trading activities. 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 natural gas liquids market prices.

Cash Flows

Three Months Ended March 31*(In millions)*	**2009**	2008
Net cash provided from (used in) operating activities	**$ 63.4**	$ (16.8)
Net cash used in investing activities	**(247.7)**	(125.8)
Net cash provided from financing activities	**156.3**	136.5

The increase of approximately $80.2 million in net cash provided from operating activities during the three months ended March 31, 2009 as compared to the same period in 2008 was primarily due to:

- higher fuel recoveries at OG&E during the three months ended March 31, 2009 as compared to the same period in 2008; 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 quarter 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 increase of approximately $121.9 million in net cash used in investing activities during the three months ended March 31, 2009 as compared to the same period in 2008 related to higher levels of capital expenditures primarily related to OU Spirit and the extra high voltage transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma being constructed by OG&E.

The increase of approximately $19.8 million in net cash provided from financing activities during the three months ended March 31, 2009 as compared to the same period in 2008 primarily related to:

- higher levels of short-term debt in the first quarter of 2009;
- proceeds received from borrowings under Enogex's revolving credit agreement during the three months ended March 31, 2009; and
- an increase in the issuance of common stock during the three months ended March 31, 2009.

These increases in net cash provided from financing activities were partially offset by proceeds received from the issuance of long-term debt in the first quarter of 2008.

Future Capital Requirements

Capital Expenditures

The Company's consolidated estimates of capital expenditures are approximately: 2009 - $888.6 million, 2010 - $430.1 million, 2011 - $466.1 million, 2012 - $394.8 million, 2013 - $359.2 million and 2014 - $362.9 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 and Distribution	$1,313.8	$ 199.8	$ 451.6	$ 441.6	$ 220.8
OG&E Base Generation	282.1	40.0	78.9	106.9	56.3
OG&E Other	129.8	12.2	44.6	47.8	25.2
Total OG&E Base Transmission, Distribution Generation and Other	1,725.7	252.0	575.1	596.3	302.3
OG&E Known and Committed Projects:					
Sunnyside-Hugo (345 kV)	126.8	1.0	86.7	39.1	---
Sooner-Rose Hill (345 kV)	68.0	1.0	67.0	---	---
Oklahoma City, OK to Woodward, OK (345 kV)	180.7	172.2	8.5	---	---
OG&E System Hardening	35.3	3.8	31.5	---	---
OG&E OU Spirit	225.7	214.0	11.7	---	---
Total OG&E Known and Committed Projects	636.5	392.0	205.4	39.1	---
Total OG&E	2,362.2	644.0	780.5	635.4	302.3
OGE Energy and OERI	85.1	13.5	27.4	28.6	15.6
Enogex (Base Maintenance and Known and Committed Projects)	454.4	231.1	88.3	90.0	45.0
Total Consolidated	$2,901.7	$ 888.6	$ 896.2	$ 754.0	$ 362.9

The Base Capital Expenditure Plan above excludes any environmental expenditures associated with Best Available Retrofit Technology ("BART") requirements due to the uncertainty regarding BART costs. As previously disclosed in the Company's 2008 Form 10-K, due to comments from the U.S. Environmental Protection Agency ("EPA") that OG&E's proposed initial BART compliance plan would not satisfy the applicable requirements, OG&E completed additional analysis. On May 30, 2008, OG&E filed the results with the Oklahoma Department of Environmental Quality ("ODEQ") for the affected generating units. In the May 30, 2008 filing, OG&E indicated its intention to install low nitrogen oxide ("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. In a letter dated November 4, 2008, the EPA notified the ODEQ that they had completed their review of BART applications for all affected sources in Oklahoma, which included OG&E. The EPA did not approve or disapprove the applications, however, additional information was requested from the ODEQ by the EPA regarding OG&E's plan. The Company cannot predict what action the EPA or the ODEQ will take in response to OG&E's May 30, 2008 filing or the November 4, 2008 letter from the EPA. The original deadline for the ODEQ to submit a state implementation plan 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 state implementation plan. If the ODEQ fails to meet this deadline, the EPA can issue a Federal implementation plan. Until the compliance plan is approved, the total cost of compliance, including capital expenditures, cannot be estimated by OG&E with a reasonable degree of certainty. Due to this uncertainty and timing regarding BART costs, the chart above does not include the $110 million of capital expenditures or any other potential BART costs.

The table below summarizes the capital expenditures for the Company’s growth opportunities related to the “Balanced Portfolio 3E” projects the SPP approved on April 28, 2009 and the projects related to the joint venture between OGE Energy and Electric Transmission America (see Note 14 of Notes to Condensed Consolidated Financial Statements for

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a further discussion). These capital expenditures are not currently included in the Company's Base Capital Expenditure Plan in the table above.

(In millions)	Total	2009	2010-2011	2012-2013
OG&E Balanced Portfolio 3E Projects	$ 247.3	$ ---	$ 79.3	$ 168.0
OGE Energy and Electric Transmission America joint venture (345 kV)	251.0	---	76.0	175.0
Total	$ 498.3	$ ---	$ 155.3	$ 343.0

Additional capital expenditures beyond those identified in the charts above, including additional incremental growth opportunities in transmission assets, wind generation assets and at Enogex will be evaluated based upon the financial viability of the projects assuming they are financed via the traditional capital structure. The capital expenditure projections related to Enogex in the chart on the previous page reflect base market conditions at April 30, 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

The Company previously disclosed in its 2008 Form 10-K that it may contribute up to $50 million to its pension plan during 2009. In April 2009, the Company contributed approximately $20 million to its pension plan and currently expects to contribute an additional $30 million to its pension plan during the remainder of 2009. Any expected contributions to the pension plan during 2009 would be discretionary contributions, anticipated to be in the form of cash, and are not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

Future Sources of Financing

Management expects that 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. At March 31, 2009 and December 31, 2008, respectively, the Company had approximately $351.5 million and $298.0 million in outstanding borrowings under OGE Energy's and OG&E's revolving credit agreements. At March 31, 2009, Enogex had approximately $200.0 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. There were no outstanding commercial paper borrowings at March 31, 2009 or December 31, 2008. The following table provides information regarding the Company's revolving credit agreements and available cash at March 31, 2009.

Revolving Credit Agreements and Available Cash *(In millions)*				
Entity	Aggregate Commitment	Amount Outstanding	Weighted-Average Interest Rate	Maturity
OGE Energy	$ 596.0	$ 298.0		