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

FORM 10-K

(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 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)
Registrant's telephone number, including area code: **405-553-3000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange
Rights to Purchase Series A Preferred Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes x No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
Yes o No x

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this Chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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 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 Act). Yes o No x

At June 30, 2009, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of shares of common stock held by non-affiliates was $2,725,078,180 based on the number of shares held by non-affiliates (96,224,512) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $28.32.

At January 31, 2010, 97,048,304 shares of common stock, par value $0.01 per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
The Proxy Statement for the Company's 2010 annual meeting of shareowners is incorporated by reference into Part III of this Form 10-K.

OGE ENERGY CORP.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2009

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FORWARD-LOOKING STATEMENTS

Except for the historical statements contained herein, the matters discussed in this Form 10-K, including those matters discussed in "Item 7. 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 vary materially. In addition to the specific risk factors discussed in "Item 1A. Risk Factors" and "Item 7. 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;
- the ability of OGE Energy Corp. (collectively, with its subsidiaries, the "Company") and its subsidiaries to access the capital markets and obtain financing on favorable terms;
- prices and availability of electricity, coal, natural gas and natural gas liquids, each on a stand-alone basis and in relation to each other;
- business conditions in the energy and natural gas midstream industries;
- competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company;
- unusual weather;
- availability and prices of raw materials for current and future construction projects;
- Federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company's markets;
- environmental laws and regulations that may impact the Company's operations;
- changes in accounting standards, rules or guidelines;
- the discontinuance of accounting principles for certain types of rate-regulated activities;
- creditworthiness of suppliers, customers and other contractual parties;
- the higher degree of risk associated with the Company's nonregulated business compared with the Company's regulated utility business; 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 this Form 10-K.

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

PART I

Item 1. Business.

THE COMPANY

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. For financial information regarding these segments, see Note 12 of Notes to Consolidated Financial Statements. The Company was incorporated in August 1995 in the state of Oklahoma and its principal executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone (405) 553-3000.

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 rate 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 gas business in 1928 and is no longer engaged in the gas distribution business.

Enogex LLC and its subsidiaries ("Enogex") are providers of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. Prior to January 1, 2008, Enogex owned OGE Energy Resources, Inc. ("OERI"), whose primary operations are in natural gas marketing. On January 1, 2008, Enogex distributed the stock of OERI to OGE Energy. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream, LLC joint venture ("Atoka") through Enogex Atoka LLC, a wholly-owned subsidiary of Enogex Gathering & Processing LLC. Enogex is a Delaware single-member limited liability company. Effective July 1, 2009, Enogex LLC formed a new entity, Enogex Gathering & Processing LLC, a wholly-owned subsidiary of Enogex, for purposes of holding the membership interests of Enogex Gas Gathering LLC, Enogex Products LLC ("Products") and Enogex Atoka LLC, which were previously direct wholly-owned subsidiaries of Enogex LLC.

In July 2008, OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture, conducting business as Tallgrass Transmission L.L.C. ("Tallgrass"), to construct high-capacity transmission line projects. The Company owns 50 percent of Tallgrass. Tallgrass is intended to allow the participating companies to lead development of renewable wind by sharing capital costs associated with transmission construction. Tallgrass' initial projects could 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 Southwest Power Pool ("SPP") study estimates cost for the two projects if constructed as 765 kV lines to be approximately $500 million, of which OGE Energy's portion would be approximately $250 million. See "Regulation and Rates – Recent Regulatory Matters – Tallgrass Joint Venture" for a further discussion of Tallgrass.

Company Strategy

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

OG&E has been focused on increased investment to preserve system reliability and meet load growth, leverage unique geographic position to develop renewable energy resources for wind and transmission, replace infrastructure equipment, replace aging transmission and distribution systems, provide new products and services, provide energy management solutions to OG&E's customers through the Smart Grid program (discussed below) and deploy newer technology that improves operational, financial and environmental performance. As part of this plan, OG&E has taken, or has committed to take, the following actions:

- in January 2007, a 120 megawatt ("MW") wind farm in northwestern Oklahoma ("Centennial") was placed in service;
- in September 2008, OG&E purchased a 51 percent interest in the 1,230 MW natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma ("Redbud Facility");
- in 2008, OG&E announced a "Positive Energy Smart Grid" initiative that will empower customers to proactively manage their energy consumption during periods of peak demand. As a result of the American Recovery and Reinvestment Act of 2009 ("ARRA") signed by the President into law in February 2009, OG&E requested a $130 million grant from the U.S. Department of Energy ("DOE") in August 2009 to develop its Smart Grid technology. In late October 2009, OG&E received notification from the DOE that its grant had been accepted by the DOE;
- in 2008, OG&E began construction of a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma ("Windspeed"), which is a critical first step to increased wind development in western Oklahoma. This transmission line is expected to be in service by April 2010;
- in June 2009, OG&E received SPP approval to build four 345 kV transmission lines referred to as "Balanced Portfolio 3E", which OG&E expects to begin constructing in early 2010. These transmission lines are expected to be in service between December 2012 and December 2014;
- in September 2009, OG&E signed power purchase agreements with two developers who are to build two new wind farms, totaling 280 MWs, in northwestern Oklahoma which OG&E intends to add to its power-generation portfolio by the end of 2010. OG&E will continue to evaluate renewable opportunities to add to its power-generation portfolio in the future;
- in November and December 2009, the individual turbines were placed in service related to the OU Spirit wind project in western Oklahoma ("OU Spirit"), which added 101 MWs of wind capacity to OG&E's wind portfolio; and
- OG&E's construction initiative from 2010 to 2015 includes approximately $2.6 billion in major projects designed to expand capacity, enhance reliability and improve environmental performance. This construction initiative also includes strengthening and expanding the electric transmission, distribution and substation systems and replacing aging infrastructure.

OG&E continues to pursue additional renewable energy and the construction of associated transmission facilities required to support this renewable expansion. OG&E also is promoting Demand Side Management programs to encourage more efficient use of electricity. See "Recent Regulatory Matters – OG&E Conservation and Energy Efficiency Programs" for a further discussion. If these initiatives are successful, OG&E believes it may be able to defer the construction of any incremental fossil fuel generation capacity until 2020.

Increases in generation and the building of transmission lines are subject to numerous regulatory and other approvals, including appropriate regulatory treatment from the OCC and, in the case of transmission lines, the SPP. Other projects involve installing new emission-control and monitoring equipment at existing OG&E power plants to help meet OG&E's commitment to comply with current and future environmental requirements. For additional information regarding the above items and other regulatory matters, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations" and Note 14 of Notes to Consolidated Financial Statements.

Enogex plans to continue to implement improvements to enhance long-term financial performance of its mid-continent assets through more efficient operations and effective commercial management of the assets, capturing growth opportunities through expansion projects, increased utilization of existing assets and strategic acquisitions. Enogex also plans to continue to add additional fee-based business to its portfolio as opportunities become available. In addition, Enogex is seeking to diversify its gathering, processing and transportation businesses principally by expanding into other geographic areas that are complementary with the Company's strategic capabilities. Enogex expects to accomplish this diversification either by undertaking organic growth projects or through strategic acquisitions. Over the past several years, Enogex has been able to take advantage of numerous organic growth projects within its existing footprint including:

- expansions on the east side of Enogex's gathering system, primarily in the Woodford Shale play in southeastern Oklahoma through construction of new facilities and expansion of existing facilities and its interest in Atoka; and
- expansions on the west side of Enogex's gathering system, primarily in the Granite Wash play, Woodford Shale play and Atoka play in western Oklahoma and the Granite Wash play and Atoka play in the Wheeler County, Texas area, which is located in the Texas Panhandle.

In addition to focusing on growing its earnings and improving cash flow, Enogex intends to continue to prudently manage its business and execute on organic growth initiatives. The Company's business strategy is to continue maintaining the diversified asset position of OG&E and Enogex so as to provide competitive energy products and services to customers primarily in the south central United States. The Company will continue to focus on those products and services with limited or manageable commodity price exposure. Also, the Company believes that many of the risk management practices, commercial skills and market information available from OERI provide value to all of the Company's businesses.

ELECTRIC OPERATIONS - OG&E

General

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E. OG&E furnishes retail electric service in 269 communities and their contiguous rural and suburban areas. At December 31, 2009, four other communities and two rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from OG&E for resale. The service area covers approximately 30,000 square miles in Oklahoma and western Arkansas, including Oklahoma City, the largest city in Oklahoma, and Fort Smith, Arkansas, the second largest city in that state. Of the 269 communities that OG&E serves, 243 are located in Oklahoma and 26 in Arkansas. OG&E derived approximately 90 percent of its total electric operating revenues for the year ended December 31, 2009 from sales in Oklahoma and the remainder from sales in Arkansas.

OG&E's system control area peak demand during 2009 was approximately 6,418 MWs on July 13, 2009. OG&E's load responsibility peak demand was approximately 5,969 MWs on July 13, 2009. As reflected in the table below and in the operating statistics that follow, there were approximately 25.9 million megawatt-hour ("MWH") sales to OG&E's customers ("system sales") in 2009, 26.8 million MWH system sales in 2008 and 26.4 million MWH system sales in 2007. Variations in system sales for the three years are reflected in the following table:

Year ended December 31 *(In millions)*	**2009**	**2009 vs. 2008 Decrease**	2008	2008 vs. 2007 Increase	2007
System Sales (A)	**25.9**	**(3.4)%**	26.8	1.5%	26.4

(A) Sales are in millions of MWHs.

OG&E is subject to competition in various degrees from government-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators. Oklahoma law forbids the granting of an exclusive franchise to a utility for providing electricity.

Besides competition from other suppliers or marketers of electricity, OG&E competes with suppliers of other forms of energy. The degree of competition between suppliers may vary depending on relative costs and supplies of other forms of energy.

OKLAHOMA GAS AND ELECTRIC COMPANY
CERTAIN OPERATING STATISTICS

Year ended December 31 *(In millions)*	**2009**	2008	2007
ELECTRIC ENERGY *(Millions of MWH)*			
Generation (exclusive of station use)	**25.0**	25.7	23.8
Purchased	**3.9**	4.3	5.2
Total generated and purchased	**28.9**	30.0	29.0
Company use, free service and losses	**(2.0)**	(1.8)	(1.9)
Electric energy sold	**26.9**	28.2	27.1
ELECTRIC ENERGY SOLD *(Millions of MWH)*			
Residential	**8.7**	9.0	8.7
Commercial	**6.4**	6.5	6.3
Industrial	**3.6**	4.0	4.2
Oilfield	**2.9**	2.9	2.8
Public authorities and street light	**3.0**	3.0	3.0
Sales for resale	**1.3**	1.4	1.4
System sales	**25.9**	26.8	26.4
Off-system sales (A)	**1.0**	1.4	0.7
Total sales	**26.9**	28.2	27.1
ELECTRIC OPERATING REVENUES *(In millions)*			
Residential	**$ 717.9**	$ 751.2	$ 706.4
Commercial	**439.8**	479.0	450.1
Industrial	**172.1**	219.8	221.4
Oilfield	**132.6**	151.9	140.9
Public authorities and street light	**167.7**	190.3	181.4
Sales for resale	**53.6**	64.9	68.8
Provision for rate refund	**(0.6)**	(0.4)	0.1
System sales revenues	**1,683.1**	1,856.7	1,769.1
Off-system sales revenues	**31.8**	68.9	35.1
Other	**36.3**	33.9	30.9
Total operating revenues	**$ 1,751.2**	$ 1,959.5	$ 1,835.1
ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)*			
Residential	**665,344**	659,829	653,369
Commercial	**85,537**	85,030	83,901
Industrial	**3,056**	3,086	3,142
Oilfield	**6,437**	6,424	6,324
Public authorities and street light	**16,124**	15,670	15,446
Sales for resale	**52**	49	52
Total	**776,550**	770,088	762,234
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 1,083.50**	$ 1,145.05	$ 1,086.03
Average annual use (kilowatt-hour (“KWH”))	**13,197**	13,659	13,325
Average price per KWH (cents)	**$ 8.21**	$ 8.38	$ 8.15

(A) Sales to other utilities and power marketers.

Regulation and Rates

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's wholesale electric tariffs, transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the DOE has jurisdiction over some of OG&E's facilities and operations. For the year ended December 31, 2009, approximately 89 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and three percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of the Company. The order required that, among other things, (i) the Company permit the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E, (ii) the Company employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) the Company refrain from pledging OG&E assets or income for affiliate transactions. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of the Company and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates.

Recent Regulatory Matters

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. On July 24, 2009, the OCC issued an order authorizing: (i) an annual net increase of approximately $48.3 million in OG&E's rates to its Oklahoma retail customers, which includes an increase in the residential customer charge from $6.50/month to $13.00/month, (ii) creation of a new recovery rider to permit the recovery of up to $20 million of capital expenditures and operation and maintenance expenses associated with OG&E's smart grid project in Norman, Oklahoma, which was implemented in February 2010, (iii) continued utilization of a return on equity ("ROE") of 10.75 percent under various recovery riders previously approved by the OCC and (iv) recovery through OG&E's fuel adjustment clause of approximately $4.8 million annually of certain expenses that historically had been recovered through base rates. New electric rates were implemented August 3, 2009. OG&E expects the impact of the rate increase on its customers and service territory to be minimal over the next 12 months as the rate increase will be more than offset by lower fuel costs attributable to prior fuel over recoveries and from lower than forecasted fuel costs in 2010.

OG&E Arkansas Rate Case Filing. In August 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 in the 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. On May 20, 2009, the APSC approved a general rate increase of approximately $13.3 million, which excludes approximately $0.3 million in storm costs. The APSC order 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. OG&E implemented the new electric rates effective June 1, 2009.

OG&E OU Spirit Wind Power Project. OG&E signed contracts on July 31, 2008 for approximately 101 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with OU Spirit. As discussed below, OU Spirit is part of OG&E's goal to increase its wind power generation portfolio in the near future. On July 30, 2009, OG&E filed an application with the OCC requesting pre-approval to recover from Oklahoma customers the cost to construct OU Spirit at a cost of approximately $265.8 million. On October 15, 2009, all parties to this case signed a settlement agreement that would provide pre-approval of OU Spirit and authorize OG&E to begin recovering the costs of OU Spirit through a rider mechanism as the 44 turbines were placed into service in November and December 2009 and began delivering electricity to OG&E's customers. The rider will be in effect until OU Spirit is added to OG&E's regulated rate base as part of OG&E's next general rate case, which is expected to be based on a 2010 test year and completed in 2011, at which time the rider will cease. The settlement agreement also assigns to OG&E's customers the proceeds from the sale of OU Spirit renewable energy credits to the University of Oklahoma. The settlement agreement permits the recovery of up to $270 million of eligible construction costs, including recovery of the costs of the conservation project for the lesser prairie chicken as discussed below. The net impact on the average residential customer's 2010 electric bill is estimated to be approximately 90 cents per month, decreasing to 80 cents per month in 2011. On November 25, 2009, OG&E received an order from the OCC approving the settlement agreement in this case, with the rider being implemented on December 4, 2009. Capital expenditures associated with this project were approximately $270 million.

In connection with OU Spirit, in January 2008, OG&E filed with the SPP for a Large Generator Interconnection Agreement ("LGIA") for this project. Since January 2008, the SPP has been studying this requested interconnection to determine the feasibility of the request, the impact of the interconnection on the SPP transmission system and the facilities needed to accommodate the interconnection. Given the backlog of interconnection requests at the SPP, there has been significant delay in completing the study process and in OG&E receiving a final LGIA. On May 29, 2009, OG&E executed an interim LGIA, allowing OU Spirit to interconnect to the transmission grid, subject to certain conditions. In connection with the interim LGIA, OG&E posted a letter of credit with the SPP of approximately $10.9 million, which was later reduced to approximately $9.9 million in October 2009 and further reduced to approximately $9.2 million in February 2010, related to the costs of upgrades required for OG&E to obtain transmission service from its new OU Spirit wind farm. The SPP filed the interim LGIA with the FERC on June 29, 2009. On August 27, 2009, the FERC issued an order accepting the interim LGIA, subject to certain conditions, which enables OU Spirit to interconnect into the transmission grid until the final LGIA can be put in place, which is expected by mid-2010.

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

OG&E Renewable Energy Filing. OG&E announced in October 2007 its goal to increase its wind power generation over the following four years from its then current 170 MWs to 770 MWs and, as part of this plan, on December 8, 2008, OG&E issued a request for proposal ("RFP") to wind developers for construction of up to 300 MWs of new capability, which OG&E intends to add to its power-generation portfolio by the end of 2010. In June 2009, OG&E announced that it had selected a short list of bidders for a total of 430 MWs and that it was considering acquiring more than the approximately 300 MWs of wind energy originally contemplated in the initial RFP. On September 29, 2009, OG&E announced that, from its short list, it had reached agreements with two developers who are to build two new wind farms, totaling 280 MWs, in northwestern Oklahoma. Under the terms of the agreements, CPV Keenan is to build a 150 MW wind farm in Woodward County and Edison Mission Energy is to build a 130 MW facility in Dewey County near Taloga. The agreements are both 20-year power purchase agreements, under which the developers are to build, own and operate the wind generating facilities and OG&E will purchase their electric output. On October 30, 2009, OG&E filed separate applications with the OCC seeking pre-approval for the recovery of the costs associated with purchasing power from these projects. On December 9, 2009, all parties to these cases signed settlement agreements whereby the stipulating parties requested that the OCC issue orders: (i) finding that the execution of the power purchase agreements complied with the OCC competitive bidding rules, are prudent and are in the public's interest, (ii) approving the power purchase agreements and (iii) authorizing OG&E to recover the costs of the power purchase agreements through OG&E's fuel adjustment clause. On January 5, 2010, OG&E received an order from the OCC approving the power purchase agreements and authorizing OG&E to recover the costs of the power purchase agreements through OG&E's fuel adjustment clause. The two wind farms are expected to be in service by the end of 2010. Negotiations with the third bidder on OG&E's short list announced in June, for an additional 150 MWs of wind energy from Texas County were terminated in early October. OG&E will continue to evaluate renewable opportunities to add to its power-generation portfolio in the future.

OG&E Windspeed Transmission Line Project. OG&E filed an application on May 19, 2008 with the OCC requesting pre-approval to recover from Oklahoma customers the cost to construct the Windspeed transmission line at a construction cost of approximately $211 million, plus approximately $7 million in allowance for funds used during construction ("AFUDC"), for a total of approximately $218 million. This transmission line is a critical first step to increased wind development in western Oklahoma. In the application, OG&E also requested authorization to implement a recovery rider to be effective when the transmission line is completed and in service, which is expected during April 2010. Finally, the application requested the OCC to approve new renewable tariff offerings to OG&E's Oklahoma customers. A settlement agreement was signed by all parties in the matter on July 31, 2008. Under the terms of the settlement agreement, the parties agreed that OG&E will: (i) receive pre-approval for construction of the Windspeed transmission line and a conclusion that the construction costs of the transmission line are prudent, (ii) receive a recovery rider for the revenue requirement of the $218 million in construction costs and AFUDC when the transmission line is completed and in service until new rates are implemented in an expected 2011 rate case and (iii) to the extent the construction costs and AFUDC for the transmission line exceed $218 million, OG&E be permitted to show that such additional costs are prudent and allowed to be recovered. On September 11, 2008, the OCC issued an order approving the settlement agreement. At December 31, 2009, the construction costs and AFUDC incurred were approximately $184.9 million. Separately, on July 29, 2008, the SPP Board of Directors approved the proposed transmission line discussed above. On February 2, 2009, OG&E received SPP approval to begin construction of the transmission line and the associated Woodward District EHV substation. In 2009, OG&E received a favorable outcome in five local court cases challenging OG&E's use of eminent domain to obtain rights-of-way. The capital expenditures related to this project are presented in the summary of capital expenditures for known and committed projects in

"Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

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

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

In 2007, the SPP notified OG&E to construct approximately 44 miles of new 345 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 June 2012. The capital expenditures related to this project are presented in the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

In January 2009, OG&E received notification from the SPP to begin construction on approximately 50 miles of new 345 kV transmission line and substation upgrades at OG&E's Sunnyside substation, among other projects. In April 2009, Western Farmers Electric Cooperative ("WFEC") assigned to OG&E the construction of 50 miles of line designated by the SPP to be built by the WFEC. The new line will extend from OG&E's Sunnyside substation near Ardmore, Oklahoma, approximately 100 miles to the Hugo substation owned by the WFEC near Hugo, Oklahoma. OG&E began preliminary line routing and acquisition of rights-of-way in June 2009. When construction is completed, which is expected in April 2012, the SPP will allocate a portion of the annual revenue requirement to OG&E customers according to the base-plan funding mechanism as provided in the SPP tariff for application to such improvements. The capital expenditures related to this project are presented in the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

On April 28, 2009, the SPP approved the Balanced Portfolio 3E projects. Balanced Portfolio 3E includes four projects to be built by OG&E and includes: (i) construction of 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, which is expected to be in service by December 2014, (ii) construction of approximately 72 miles of transmission line from OG&E's Woodward District EHV substation in a southwestern direction to the Oklahoma/Texas Stateline to a companion transmission line to be built by Southwestern Public Service to its Tuco substation at a cost of approximately $120 million for OG&E, which is expected to be in service by April 2014, (iii) construction of approximately 38 miles of transmission line from OG&E's Sooner substation in an eastern direction to the Grand River Dam Authority Cleveland substation at an estimated cost of approximately $41 million for OG&E, which is expected to be in service by December 2012 and (iv) construction of a new substation near Anadarko which is expected to consist of a 345/138 kV transformer and substation breakers and will be built in OG&E's portion of the Cimarron-Lawton East Side 345 kV line at an estimated cost of approximately $8 million for OG&E, which is expected to be in service by December 2012. On June 19, 2009, OG&E received a notice to construct the Balanced Portfolio 3E projects from the SPP. On July 23, 2009, OG&E responded to the SPP that OG&E will construct the Balanced Portfolio 3E projects discussed above beginning in early 2010. The capital expenditures related to the Balanced Portfolio 3E projects are presented in the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

OG&E Conservation and Energy Efficiency Programs. In June and September 2009, OG&E filed applications with the APSC and the OCC seeking approval of a comprehensive Demand Program portfolio designed to build on the success of its earlier programs and further promote energy efficiency and conservation for each class of OG&E customers. Several programs are proposed in these applications, ranging from residential weatherization to commercial lighting. In seeking approval of these new programs, OG&E also seeks recovery of the program and related costs through a rider that would be added to customers' electric bills. In Arkansas, OG&E's program is expected to cost approximately $2 million over an 18-month period and is expected to increase the average residential electric bill by less than $1.00 per month. In Oklahoma, OG&E's program is expected to cost approximately $45 million over three years and is expected to increase the average residential electric bill by less than $1.00 per month in 2010 and by approximately $1.40 per month in 2011 and 2012 depending on the success of the programs. In addition to program cost recovery, the OCC also granted OG&E recovery of: (i) lost revenues resulting from the reduced KWH sales between rate cases and (ii) performance-based incentives of 15 percent of the net savings associated with the programs. A hearing in the APSC matter was held on October 29, 2009 and OG&E received an order in this matter on February 3, 2010. A settlement agreement was signed in the OCC matter by several parties to this case on January 15, 2010 with a hearing being held on January 21, 2010, where the parties who had not previously signed the settlement agreement indicated that they did not oppose the settlement agreement. OG&E received an order in the OCC matter on February 10, 2010.

OG&E Smart Grid Application. In February 2009, the President signed into law the ARRA. Several provisions of this law relate to issues of direct interest to the Company including, in particular, financial incentives to develop smart grid technology, transmission infrastructure and renewable energy. After review of the ARRA, OG&E filed a grant request on August 4, 2009 for $130 million with the DOE to be used for the Smart Grid application in OG&E's service territory. On October 27, 2009, OG&E received notification from the DOE that its grant had been accepted by the DOE for the full requested amount of $130 million. Receipt of the grant monies is contingent upon successful negotiations with the DOE on final details of the award. OG&E expects to file an application with the OCC requesting pre-approval for system-wide deployment of smart grid technology and a recovery rider, including a credit for the Smart Grid grant during the first quarter of 2010. Separately, on November 30, 2009, OG&E requested a grant with a 50 percent match of up to $5 million for a variety of types of smart grid training for OG&E's workforce. Recipients of the grant are expected to be announced in the first quarter of 2010.

Tallgrass Joint Venture. In July 2008, Tallgrass was formed to construct high-capacity transmission line projects. The Company owns 50 percent of Tallgrass. Tallgrass is intended to allow the participating companies to lead development of renewable wind by sharing capital costs associated with transmission construction. The Tallgrass projects are subject to creation by the SPP of a cost allocation method that would spread the total cost across the SPP region. OGE Energy is uncertain as to the timing of when the cost allocation method will be developed and approved. OGE Energy filed an application with the FERC in October 2008 for cost recovery of these projects subject to SPP and FERC approval for these projects. On December 2, 2008, the FERC granted Tallgrass' request for transmission rate incentives for the initial projects, established a base ROE for initial projects, approved certain accounting treatments for the initial projects and set the formula rate and accompanying protocols for hearing and settlement discussions. Tallgrass' initial projects could include 765 kV lines from Woodward 120 miles northwest to Guymon in the Oklahoma Panhandle and from Woodward 50 miles north to the Kansas border. An SPP study estimates the cost for the two projects if constructed as 765 kV lines to be approximately $500 million, of which OGE Energy's portion would be approximately $250 million. The capital expenditures related to the Tallgrass projects discussed above are excluded from the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements." The SPP continues to review the initial Tallgrass projects and has not made a final determination whether these projects should be built. The SPP is reviewing these projects as a portion of the list of "Priority Projects" and the SPP is expected to make decisions on these projects as to timing and voltage in the second quarter of 2010. If the SPP determines that the above 765 kV projects should be 345 kV projects, these projects are expected to be completed by OG&E. In December 2009, the Tallgrass agreement was amended between the joint venture owners to expand the joint venture from the two potential 765kV projects discussed above to also include any potential 765 kV projects in Oklahoma that any subsidiary of the joint venture partners has the right to construct. The period of the agreement was established for seven years unless earlier terminated via the conditions precedent, which expire in December of 2011.

See Note 14 of Notes to Consolidated Financial Statements for further discussion of these matters, as well as a discussion of additional regulatory matters, including, among other things, system hardening filing, security enhancements filing, FERC formula rate filing and review of OG&E's fuel adjustment clause.

Regulatory Assets and Liabilities

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

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

At December 31, 2009 and 2008, OG&E had regulatory assets of approximately $451.4 million and $464.3 million, respectively, and regulatory liabilities of approximately $363.0 million and $164.4 million, respectively. See Note 1 of Notes to Consolidated Financial Statements for a further discussion.

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If the Company were required to discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets; the financial effects of which could be significant.

Rate Structures

Oklahoma

OG&E's standard tariff rates include a cost-of-service component (including an authorized return on capital) plus a fuel adjustment clause mechanism that allows OG&E to pass through to customers variances (either positive or negative) in the actual cost of fuel as compared to the fuel component in OG&E's most recently approved rate case.

OG&E offers several alternate customer programs and rate options. The Guaranteed Flat Bill ("GFB") option for residential and small general service accounts allows qualifying customers the opportunity to purchase their electricity needs at a set price for an entire year. Budget-minded customers that desire a fixed monthly bill may benefit from the GFB option. A second tariff rate option provides a "renewable energy" resource to OG&E's Oklahoma retail customers. This renewable energy resource is a wind power purchase program and is available as a voluntary option to all of OG&E's Oklahoma retail customers. OG&E's ownership and access to wind resources makes the renewable wind power option a possible choice in meeting the renewable energy needs of our conservation-minded customers and provides the customers with a means to reduce their exposure to increased prices for natural gas used by OG&E as boiler fuel. Another program being offered to OG&E's commercial and industrial customers is a voluntary load curtailment program called Load Reduction. This program provides customers with the opportunity to curtail usage on a voluntary basis when OG&E's system conditions merit curtailment action. Customers that curtail their usage will receive payment for their curtailment response. This voluntary curtailment program seeks customers that can curtail on most curtailment event days, but may not be able to curtail every time that a curtailment event is required.

OG&E also has two rate classes, Public Schools-Demand and Public Schools Non-Demand, that will provide OG&E with flexibility to provide targeted programs for load management to public schools and their unique usage patterns. OG&E also created service level fuel differentiation that allows customers to pay fuel costs that better reflect operational energy losses related to a specific service level. Lastly, OG&E implemented a military base rider that demonstrates Oklahoma's continued commitment to our military partners.

The previously discussed rate options, coupled with OG&E's other rate choices, provide many tariff options for OG&E's Oklahoma retail customers. The revenue impacts associated with these options are not determinable in future years because customers may choose to remain on existing rate options instead of volunteering for the alternative rate option choices. Revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose alternative rate options. OG&E's rate choices, reduction in cogeneration rates, acquisition of additional generation resources and overall low costs of production and deliverability are expected to provide valuable benefits for OG&E's customers for many years to come.

Arkansas

OG&E's standard tariff rates include a cost-of service component (including an authorized return on capital) plus an energy cost recovery mechanism that allows OG&E to pass through to customers (either positive or negative) the actual cost of fuel as compared to the fuel component in OG&E's most recently approved rate case. OG&E's Arkansas rate case order in May 2009 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. OG&E also offers certain qualifying customers a "day-ahead price" rate option which allows participating customers to adjust their electricity consumption based on a price signal received from OG&E. The day-ahead price is based on OG&E's projected next day hourly operating costs.

Fuel Supply and Generation

During 2009, approximately 60 percent of the OG&E-generated energy was produced by coal-fired units, 38 percent by natural gas-fired units and two percent by wind-powered units. Of OG&E's 6,641 total MW capability reflected in the table under Item 2. Properties, approximately 3,850 MWs, or 58.0 percent, are from natural gas generation, approximately 2,570 MWs, or 38.7 percent, are from coal generation and approximately 221 MWs, or 3.3 percent, are from wind generation. Though OG&E has a higher installed capability of generation from natural gas units, it has been more economical to generate electricity for our customers using lower priced coal. Over the last five years, the weighted average cost of fuel used, by type, per million British thermal unit ("MMBtu") was as follows:

Year ended December 31	**2009**	2008	2007	2006	2005
Coal	**$ 1.65**	$ 1.11	$ 1.10	$ 1.10	$ 0.98
Natural Gas	**$ 4.02**	$ 8.40	$ 6.77	$ 7.10	$ 8.76
Weighted Average	**$ 2.50**	$ 3.30	$ 3.13	$ 2.98	$ 3.21

The decrease in the weighted average cost of fuel in 2009 as compared to 2008 was primarily due to decreased natural gas prices partially offset by increased coal transportation rates in 2009 as discussed in Note 13 of Notes to Consolidated Financial Statements. The increase in the weighted average cost of fuel in 2008 as compared to 2007 was primarily due to increased natural gas prices partially offset by decreased amounts of natural gas being burned. The increase in the weighted average cost of fuel in 2007 as compared to 2006 was primarily due to increased natural gas volumes. The decrease in the weighted average cost of fuel in 2006 as compared to 2005 was primarily due to decreased natural gas prices partially offset by increased amounts of natural gas being burned. A portion of these fuel costs is included in the base rates to customers and differs for each jurisdiction. The portion of these fuel costs that is not included in the base rates is recoverable through OG&E's fuel adjustment clauses that are approved by the OCC, the APSC and the FERC.

Coal

All of OG&E's coal-fired units, with an aggregate capability of approximately 2,570 MWs, are designed to burn low sulfur western sub-bituminous coal. OG&E purchases coal primarily under contracts expiring in years 2010, 2011 and 2015. In 2009, OG&E purchased approximately 9.9 million tons of coal from various Wyoming suppliers. The combination of all coal has a weighted average sulfur content of 0.27 percent and can be burned in these units under existing Federal, state and local environmental standards (maximum of 1.2 lbs. of sulfur dioxide ("SO2") per MMBtu) without the addition of SO2 removal systems. Based upon the average sulfur content and EPA certified emission data, OG&E's coal units have an approximate emission rate of 0.528 lbs. of SO2 per MMBtu, well within the limitations of the current provisions of the Federal Clean Air Act discussed in Note 13 of Notes to Consolidated Financial Statements.

In August 2009, OG&E issued an RFP for coal supply purchases for periods from January 2011 through December 2015. The RFP process was completed during the fourth quarter of 2009 and resulted in two new coal contracts expiring in 2015. The coal supply purchases account for approximately 50 percent of OG&E's projected coal requirements during that timeframe. Additional coal supplies to fulfill OG&E's remaining 2011 through 2015 coal requirements will be acquired through additional RFPs.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations" for a discussion of environmental matters which may affect OG&E in the future, including its utilization of coal.

Natural Gas

In August 2009, OG&E issued an RFP for gas supply purchases for periods from November 2009 through March 2010. The gas supply purchases from January through March 2010 account for approximately 18 percent of OG&E's projected 2010 natural gas requirements. The RFP process was completed on September 10, 2009. The contracts resulting from this RFP are tied to various gas price market indices that will expire in 2010. Additional gas supplies to fulfill OG&E's remaining 2010 natural gas requirements will be acquired through additional RFPs in early to mid-2010, along with monthly and daily purchases, all of which are expected to be made at market prices.

OG&E utilizes a natural gas storage facility for storage services that allows OG&E to maximize the value of its generation assets. Storage services are provided by Enogex as part of Enogex's gas transportation and storage contract with OG&E. At December 31, 2009, OG&E had approximately 1.9 million MMBtu's in natural gas storage valued at approximately $7.3 million.

Wind

OG&E's current wind power portfolio includes: (i) the 120 MW Centennial wind farm, (ii) the 101 MW OU Spirit wind farm placed in service in November and December 2009 and (iii) access to up to 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma from a 15-year contract OG&E entered into with FPL Energy that expires in 2018.

OG&E announced in October 2007 its goal to increase its wind power generation over the following four years from its then current 170 MWs to 770 MWs and, as part of this plan, on December 8, 2008, OG&E issued an RFP to wind developers for construction of up to 300 MWs of new capability which OG&E intends to add to its power-generation portfolio by the end of 2010. As part of this RFP process, on September 29, 2009, OG&E announced that it had reached agreements with two developers who are to build two new wind farms, totaling 280 MWs, in northwestern Oklahoma. Under the terms of the agreements, CPV Keenan is to build a 150 MW wind farm in Woodward County and Edison Mission Energy is to build a 130 MW facility in Dewey County near Taloga. The agreements are both 20-year power purchase agreements, under which the developers are to build, own and operate the wind generating facilities and OG&E will purchase their electric output. On January 5, 2010, OG&E received an order from the OCC approving the power purchase agreements and authorizing OG&E to recover the costs of the power purchase agreements through OG&E's fuel adjustment clause.

Safety and Health Regulation

OG&E is subject to a number of Federal and state laws and regulations, including the Federal Occupational Safety and Health Act of 1970 ("OSHA") and comparable state statutes, whose purpose is to protect the safety and health of workers. In addition, the OSHA hazard communication standard, the U.S. Environmental Protection Agency ("EPA") community right-to-know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in OG&E's operations and that this information be provided to employees, state and local government authorities and citizens. The Company believes that it is in material compliance with all applicable laws and regulations relating to worker safety and health.

NATURAL GAS PIPELINE OPERATIONS - ENOGEX

Overview

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing.

Transportation and Storage

General

Enogex LLC owns and operates approximately 2,181 miles of intrastate natural gas transportation pipelines. Enogex also owns and operates two underground storage facilities currently being operated at a working gas level of approximately 24 billion cubic feet ("Bcf"). Enogex provides fee-based firm and interruptible transportation services on both an intrastate basis and pursuant to Section 311 of the Natural Gas Policy Act ("NGPA") on an interstate basis. Enogex's obligation to provide firm transportation service means that it is obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on Enogex's part, the shipper pays a specified demand or reservation charge, whether or not it utilizes the capacity. In most intrastate firm contracts, the shipper also pays a transportation or commodity charge with respect to quantities actually transported by Enogex. Enogex's obligation to provide interruptible transportation service means that it is obligated to transport natural gas nominated by the shipper only to the extent that it has available capacity. For this service, the shipper pays no demand or reservation charge but pays a transportation or commodity charge for quantities actually shipped. Enogex derives a substantial portion of its transportation revenues from firm transportation services and leased capacity. To the extent pipeline capacity is not needed for such firm transportation services and leased capacity, Enogex offers interruptible interstate transportation services pursuant to Section 311 of the NGPA as well as interruptible intrastate transportation services.

Enogex delivers natural gas to most interstate and intrastate pipelines and end-users connected to its systems from the Arkoma and Anadarko basins (including recent growth activity in the Granite Wash play, Woodford Shale play and Atoka play in western Oklahoma and the Granite Wash play and Atoka play in the Wheeler County, Texas area, which is located in the Texas Panhandle). At December 31, 2009, Enogex was connected to 13 third-party natural gas pipelines and had 64 interconnect points. These interconnections include Panhandle Eastern Pipe Line, Southern Star Central Gas Pipeline (formerly Williams Central), Natural Gas Pipeline Company of America, Oneok Gas Transmission, Northern Natural Gas Company, ANR Pipeline, Western Farmers Electric Cooperative, CenterPoint Energy Gas Transmission Co., El Paso Natural Gas Pipeline, Quest Pipelines (KPC), Ozark Gas Transmission, L.L.C., Gulf Crossings Pipeline Company LLC and Midcontinent Express Pipeline, LLC ("MEP"). Further, Enogex is connected to 24 end-user customers, including 15 natural gas-fired electric generation facilities in Oklahoma.

Enogex owns and operates two underground natural gas storage facilities in Oklahoma, the Wetumka Storage Facility and the Stuart Storage Facility. These storage facilities are currently being operated at a working gas level of approximately 24 Bcf and have approximately 650 million cubic feet per day ("MMcf/d") of maximum withdrawal capability and approximately 650 MMcf/d of injection capability. Enogex offers both fee-based firm and interruptible storage services. Storage services offered under Section 311 of the NGPA are pursuant to terms and conditions specified in Enogex's Statement of Operating Conditions ("SOC") for gas storage and at market-based rates.

Enogex uses its storage assets to meet its contractual obligations under certain load following transportation and storage contracts, including its transportation agreement with OG&E. Enogex also periodically conducts an open season to solicit commitments for contracted storage capacity and deliverability to third parties.

Customers and Contracts

Enogex's major transportation customers are OG&E and Public Service Company of Oklahoma ("PSO"), the second largest electric utility in Oklahoma. Enogex provides gas transmission delivery services to all of PSO's natural gas-fired electric generation facilities in Oklahoma under a firm intrastate transportation contract. The PSO contract and the OG&E contract provide for a monthly demand charge plus variable transportation charges including fuel. The PSO contract expires January 1, 2013, unless extended. The stated term of the OG&E contract expired April 30, 2009, but the contract remains in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 180 days prior to the commencement of the next succeeding annual period. Because neither party provided notice of termination 180 days prior to May 1, 2010, the contract will remain in effect at least through April 30, 2011. As part of the no-notice load following contract with OG&E, Enogex provides natural gas storage services for OG&E. Enogex has been providing natural gas storage services to OG&E since August 2002 when it acquired the Stuart Storage Facility. Demand for natural gas on Enogex's system is usually greater during the summer, primarily due to demand by gas-fired electric generation facilities to serve residential and commercial electricity requirements. In 2009, 2008 and 2007, revenues from Enogex's firm intrastate transportation and storage contracts were approximately $116.8 million, $104.4 million and $103.9 million, respectively, of which approximately $47.5 million, $47.5 million and $47.4 million, respectively, was attributed to OG&E and approximately $15.3 million, $15.3 million and $13.3 million, respectively, was attributed to PSO. Revenues from Enogex's firm intrastate transportation and storage contracts represented approximately 32 percent of Enogex's consolidated gross margin on revenues ("gross margin") in 2009, 27 percent in 2008 and 29 percent in 2007.

Competition

Enogex's transportation and storage assets compete with numerous interstate and intrastate pipelines, including several of the interconnected pipelines discussed above, and storage facilities in providing transportation and storage services for natural gas. The principal elements of competition are rates, terms of services, flexibility and reliability of service. Natural gas-fired electric generation facilities contribute their highest value when they have the capability to provide load following service to the customer (*i.e.*, the ability of the generation facility to regulate generation to respond to and meet the instantaneous changes in customer demand for electricity). While the physical characteristics of natural gas-fired electric generation facilities are known to provide quick start-up, on-line functionality and the ability to efficiently provide varying levels of electric generation relative to other forms of generation, a key part of their effectiveness is contingent upon having access to an integrated pipeline and storage system that can respond quickly to meet their corresponding fluctuating fuel needs. We believe that Enogex is well positioned to compete for the needs of these generators due to the ability of its transportation and storage assets to provide no-notice load following service.

Natural gas competes with other forms of energy available to Enogex's customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas or other forms of energy as well as weather and other factors affect the demand for natural gas on Enogex's system.

Regulation

The transportation rates charged by Enogex for transporting natural gas in interstate commerce are subject to the jurisdiction of the FERC under Section 311 of the NGPA. Rates to provide such service must be “fair and equitable” under the NGPA and are subject to review and approval by the FERC at least once every three years. The rate review may, but will not necessarily, involve an administrative-type hearing before a FERC Staff panel and an administrative appellate review. In the past, Enogex has successfully settled, rather than litigated, its Section 311 rate cases. Enogex currently has two zones under its Section 311 rate structure – an East Zone and a West Zone. Enogex historically offered only interruptible Section 311 service in both zones. As of April 1, 2009, Enogex also began to offer firm Section 311 service in the East Zone.

For Section 311 service, Enogex may charge up to its maximum established zonal East and West interruptible transportation rates for interruptible transportation in one zone or cumulative maximum rates for transportation in both zones. Enogex may charge up to its maximum established firm rate for firm Section 311 transportation in its East Zone. Finally, Enogex may charge the applicable fixed zonal fuel percentage(s) for the fuel used in transporting natural gas under Section 311 on the Enogex system. The fuel percentages are the same for firm and interruptible Section 311 services.

Enogex FERC Section 311 2007 Rate Case

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

On November 13, 2007, one of the protesting intervenors in the 2007 rate case filed to consolidate the 2007 rate case with a separate Enogex application pending before the FERC allowing Enogex to lease firm capacity to MEP and with separate applications filed by MEP with the FERC for a certificate to construct and operate the new MEP pipeline and to lease firm capacity from Enogex. Enogex and MEP separately opposed this intervenor’s protests and assertions in its initial and subsequent pleadings. On July 25, 2008, the FERC issued an order approving the MEP project including the approval of a limited jurisdiction certificate authorizing the Enogex lease agreement with MEP denying the request for consolidation and rejecting all claims raised by protestors regarding the lease agreement. Accordingly, Enogex proceeded with the construction of facilities necessary to implement this service. On August 25, 2008, the same protestor sought rehearing which the FERC denied. Enogex commenced service to MEP under the lease agreement on June 1, 2009. On July 16, 2009, the protestor filed, with the United States Court of Appeals for the District of Columbia Circuit, a petition for review of the FERC’s orders approving the MEP construction and the MEP lease of capacity from Enogex requesting that such orders be modified or set aside on the grounds that they are arbitrary, capricious and contrary to law. The petitioner, the FERC and intervening parties, including Enogex, have been given an opportunity to brief the issues. Enogex expects to participate in the filing of a joint intervenors’ brief in support of the FERC’s order in this matter, which final briefing is scheduled to be completed in the third quarter of 2010.

Enogex FERC Section 311 2009 Rate Case

On March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for a 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 also filed with the FERC, as required by the FERC’s regulations, a revised SOC Applicable to Transportation Services to describe the terms, conditions and operating arrangements for the new service. Enogex made the SOC filing on February 27, 2009.

Enogex began offering firm East Zone Section 311 transportation service on April 1, 2009. The revised East and West Zone zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for the firm East Zone Section 311 transportation service and the increase in the rates for East and West Zone and interruptible Section 311 service are being collected, subject to refund, pending the FERC approval of the proposed rates. A number of parties intervened in both the rate case and the SOC filing and some additionally filed protests. Enogex filed answers to the interventions and protests in both matters. The FERC Staff served data requests on Enogex seeking additional information regarding various aspects of the filing and Enogex has submitted responses. On August 19, 2009, the FERC issued an order extending the time for action until it can make a determination whether Enogex’s rates are fair and equitable or until the

FERC determines that formal proceedings are necessary. The August 19, 2009 order also directed the FERC Staff to report to the FERC by December 29, 2009 on the status of settlement negotiations. On January 4, 2010, the FERC Staff submitted its initial settlement offer ("Offer") proposing various adjustments to Enogex's filed cost of service. Comments in response to the Offer were due on or before January 15, 2010. On January 14, 2010, Enogex asked the FERC Staff some clarifying questions regarding the Offer. Only Enogex and one intervenor filed comments on January 15, 2010, and each indicated that they were awaiting the FERC Staff's responses to the questions raised by Enogex before submitting substantive comments. The FERC Staff responded to the questions on January 20, 2010. Enogex anticipates that settlement discussions will continue.

Enogex 2010 Fuel Filing

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

On November 23, 2009, Enogex made its annual filing to establish fixed fuel percentages for its East Zone and West Zone for calendar year 2010 ("2010 Fuel Year"). On December 9, 2009, the FERC issued a notice establishing December 18, 2009 as the due date for any interventions and protests. Several parties filed interventions. No protests were filed, but two intervenors reserved the right to do so, contingent upon the outcome of additional discussions with Enogex. On December 30, 2009, the FERC issued a letter order directing Enogex to submit certain additional information by January 13, 2010. Enogex submitted the information requested by the FERC and is continuing to discuss the filing with the intervenors.

The FERC regulates Enogex's Section 311 transportation and storage services but does not regulate Enogex's gathering services or intrastate transportation services. A recent FERC order, Order 720A, provides that companies, such as Enogex, will be required, as of June 30, 2010 to post scheduled volume and design capacity information on a daily basis for eligible receipt and delivery points on applicable gathering and intrastate transportation facilities that meet the requirements established in the order. While the jurisdictional status of Enogex's gathering and intrastate transportation services remains unchanged under this new regulation, the requirement of the FERC order to post this information subjects Enogex to the FERC's review of the requirements of this order. In addition, the OCC, the APSC and the FERC (all of which approve various electric rates of OG&E) have the authority to examine the appropriateness of any transportation charges or other fees paid by OG&E to Enogex which OG&E seeks to recover from its ratepayers in its cost-of-service for electric service.

Certain of Enogex's pipeline operations are subject to various state and Federal safety and environmental and pipeline transportation laws. For example, the U.S. Department of Transportation ("DOT") has adopted regulations requiring pipeline operators to develop integrity management programs for its applicable pipelines. During 2009, Enogex incurred approximately $10.8 million of capital expenditures and operating costs for pipeline integrity management. Enogex currently estimates that it will incur capital expenditures and operating costs of approximately $34.2 million between 2010 and 2014 in connection with pipeline integrity management. The estimated capital expenditures and operating costs include Enogex's estimates for the assessment, remediation and prevention or other mitigation that may be determined to be necessary. At this time, Enogex cannot predict the ultimate costs of its integrity management program and compliance with this regulation because those costs will depend on the number and extent of any repairs found to be necessary. Enogex will continue to assess, remediate and maintain the integrity of its pipelines. The results of these activities could cause Enogex to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

Recent System Expansions

Over the past several years, Enogex has initiated multiple organic growth projects to increase capacity across its system.

In December 2006, Enogex entered into a firm capacity lease agreement with MEP for a primary term of 10 years (subject to possible extension) that gives MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP lease agreement is currently 272 MMcf/d, with the quantity ultimately to be leased subject to being increased by mutual agreement pursuant to the lease agreement. In addition to MEP's lease of Enogex's capacity, the MEP project included construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. In support of the MEP lease agreement, Enogex constructed approximately 43 miles of 24-inch steel pipe in Woods and Major counties in Oklahoma, and added 24,000 horsepower of electric-driven compression in Bennington, Oklahoma. Enogex's capital expenditures allocated to its support of the MEP lease agreement were approximately $99 million. Enogex commenced service to MEP under the lease agreement on June 1, 2009.

In order to accommodate additional deliveries to Bennington, Oklahoma, Enogex is planning to add an incremental 13,800 horsepower of gas turbine compression at its Bennington compressor station, as well as other system upgrades. This project is expected to be in service in May 2010. The capital expenditures associated with these projects are expected to be approximately $24 million.

In 2009, Enogex began construction of an approximately 36-mile, 16-inch steel intrastate transportation pipeline and 3,750 horsepower of electric compression. This transmission pipeline, which is scheduled to be completed by October 2010, will provide gas delivery to a natural-gas fired electric generation facility being constructed by Associated Electric Cooperative, Inc. ("AECI") near Pryor, Oklahoma. Up to approximately $64 million of Enogex's construction costs are subject to reimbursement in full by AECI as the project progresses. Enogex does not anticipate that the amount of construction costs will exceed $64 million.

Gathering and Processing

General

Enogex provides well connect, gathering, measurement, treating, dehydration, compression and processing services for various types of producing wells owned by various sized producers who are active in the areas in which Enogex operates. Most natural gas produced at the wellhead contains natural gas liquids ("NGLs"). Natural gas produced in association with crude oil typically contains higher concentrations of NGLs than natural gas produced from gas wells. This high-content, or "rich," natural gas is generally not acceptable for transportation in the nation's transmission pipeline system or for commercial use. The streams of processable natural gas gathered from wells and other sources are gathered into Enogex's gas gathering systems and are delivered to processing plants for the extraction of NGLs, leaving residual dry gas that meets transmission pipeline and commercial quality specifications. Enogex is active in the extraction and marketing of NGLs from natural gas. The liquids extracted include condensate liquids, marketable ethane, propane, butanes and natural gasoline mix. The residue gas remaining after the liquid products have been extracted consists primarily of ethane and methane.

Enogex's gathering system includes approximately 5,846 miles of natural gas gathering pipelines with approximately 1.25 trillion British thermal units per day of average daily gathered volumes during 2009. Enogex owns and operates eight natural gas processing plants with a total inlet capacity of approximately 943 MMcf/d, has a 50 percent interest in and operates the Atoka natural gas processing plant with an inlet capacity of approximately 20 MMcf/d and has contracted to have access to up to 50 MMcf/d in two third-party plants, all in Oklahoma. Where the quality of natural gas received dictates the removal of NGLs, such gas is aggregated through the gathering system to the inlet of one or more processing plants operated or utilized by Enogex. The resulting processed stream of natural gas is then delivered from the tailgate of each plant into Enogex's intrastate natural gas transportation system. For the year ended December 31, 2009, Enogex extracted and sold approximately 493 million gallons of NGLs.

Enogex's gathering and processing business has approximately 332,000 horsepower of owned compression. Enogex also has its own compression overhaul center and specialized compression workforce.

Enogex gathers and processes natural gas pursuant to a variety of arrangements generally categorized as "fee-based", "percent-of-proceeds" and "percent-of-liquids" and "keep-whole" arrangements. Percent-of-proceeds, percent-of-liquids and keep-whole arrangements involve commodity price risk to Enogex because Enogex's margin is based in part on natural gas and NGLs prices. Enogex seeks to mitigate its exposure to fluctuations in commodity prices in several ways, including managing its contract portfolio. In managing its contract portfolio, Enogex classifies its gathering and processing contracts according to the nature of commodity risk implicit in the settlement structure of those contracts.

- *Fee-Based Arrangements*. Under these arrangements, Enogex generally is paid a fixed cash fee for performing the gathering and processing service. This fee is directly related to the volume of natural gas that flows through Enogex's system and is not directly dependent on commodity prices. A sustained decline, however, in commodity prices could result in a decline in volumes and, thus, a decrease in Enogex's fee revenues. These arrangements provide stable cash flows, but minimal, if any, upside in higher commodity price environments. At December 31, 2009, these arrangements accounted for approximately 20 percent of Enogex's natural gas processed volumes.

- *Percent-of-Proceeds and Percent-of-Liquids Arrangements*. Under these arrangements, Enogex generally gathers raw natural gas from producers at the wellhead, transports the gas through its gathering system, processes the gas and sells the processed gas and/or NGLs at prices based on published index prices. These arrangements provide upside in high commodity price environments, but result in lower margins in low commodity price environments. The price paid to producers is based on an agreed percentage of the proceeds of the sale of processed natural gas, NGLs or both or the expected proceeds based on an index price. We refer to contracts in which Enogex shares in specified percentages of the proceeds from the sale of natural gas and NGLs as percent-of-proceeds arrangements and in which Enogex receives proceeds from the sale of NGLs or the NGLs themselves as compensation for its processing services as percent-of-liquids arrangements. Under percent-of-proceeds arrangements, Enogex's margin correlates directly with the prices of natural gas and NGLs. Under percent-of-liquids arrangements, Enogex's margin correlates directly with the prices of NGLs. At December 31, 2009, these arrangements accounted for approximately 45 percent of Enogex's natural gas processed volumes.

Ÿ *Keep-Whole Arrangements*. Enogex processes raw natural gas to extract NGLs and returns to the producer the full gas equivalent British thermal unit ("Btu") value of raw natural gas received from the producer in the form of either processed gas or its cash equivalent. Enogex is entitled to retain the processed NGLs and to sell them for its own account. Accordingly, Enogex's margin is a function of the difference between the value of the NGLs produced and the cost of the processed gas used to replace the thermal equivalent of those NGLs. These arrangements can provide large profit margins in favorable commodity price environments, but also can be subject to losses if the cost of natural gas exceeds the value of its thermal equivalent of NGLs. Many of Enogex's keep-whole contracts include provisions that reduce its commodity price exposure, including conditioning floors (such as the default processing fee described below) that allow the keep-whole contract to be charged a fee if the NGLs have a lower value than their gas equivalent Btu value in natural gas. At December 31, 2009, these arrangements accounted for approximately 35 percent of Enogex's natural gas processed volumes.

Enogex's gathering and processing contracts typically contain terms and conditions that require a "default processing fee" in the event the gathered gas exceeds downstream interconnect specifications. Natural gas that is greater than 1,080 Btu per cubic foot coming out of wells must typically be processed before it can enter an interstate pipeline. The default processing fee stipulates a fee to be paid to the processor if the market for NGLs is lower than the gas equivalent Btu value of the natural gas that is removed from the stream. The default processing fee helps to minimize the risk of processing gas that is greater than 1,080 Btu per cubic foot when the price of the NGLs to be extracted and sold is less than the Btu value of the natural gas that Enogex otherwise would be required to replace.

Approximately 17 percent of the commercial grade propane produced at Enogex's processing plants is sold on the local market. The balance of propane and the other NGLs produced by Enogex is delivered into pipeline facilities of a third party and transported to Conway, Kansas or Mont Belvieu, Texas, where they are sold under contract or on the spot market. Ethane, which may be optionally produced at all of Enogex's plants except the Roger Mills and Calumet plants, is also sold under contract or on the spot market.

Enogex's large diameter, rich gas gathering pipelines in western Oklahoma are configured such that natural gas from the Wheeler County area in the Texas Panhandle can flow to the Cox City, Thomas or Calumet gas processing plants. These large-diameter "super-header" gathering systems of Enogex provide gas routing flexibility for Enogex to optimize the economics of its gas processing and to improve system utilization and reliability.

As Enogex experiences increased growth in regions such as the Woodford Shale play, Enogex will evaluate the need to expand its processing plants in order to meet the growing needs of its producer customers.

Customers and Contracts

The natural gas remaining after processing is primarily taken in kind by the producer customers into Enogex's transportation pipelines for redelivery either: (i) to on-system customers such as the electric generation facilities of OG&E, PSO, other independent power producers and other end-users or (ii) into downstream interstate pipelines. Enogex's NGLs are typically sold to NGLs marketers and end-users, its condensate liquid production is typically sold to marketers and refineries and its propane is typically sold in the local market to wholesale distributors. Enogex's key natural gas producer customers include Chesapeake Energy Marketing Inc., Devon Gas Services, L.P., Apache Corporation, BP America Production Company and Samson Resources Company. During 2009, these five customers accounted for approximately 18.6 percent, 13.2 percent, 12.7 percent, 4.0 percent and 3.9 percent, respectively, of Enogex's gathering and processing volumes. During 2009, Enogex's top 10 natural gas producer customers accounted for approximately 66.6 percent of Enogex's gathering and processing volumes.

Competition

Competition for natural gas supply is primarily based on efficiency and reliability of operations, customer service, proximity to existing assets, access to markets and pricing. Competition to gather and process non-dedicated gas is based on providing the producer with the highest total value, which is primarily a function of gathering rate, processing value, system reliability, fuel rate, system run time, construction cycle time and prices at the wellhead. Enogex believes it will be able to continue to compete effectively. Enogex competes with gatherers and processors of all types and sizes, including those affiliated with various producers, other major pipeline companies and various independent midstream entities. Enogex's primary competitors are master limited partnerships who are active in its region, including Atlas Pipeline Partners, L.P., Crosstex Energy LP, DCP Midstream Partners, LP, Enbridge Energy Partners, L.P., Hiland Partners, MarkWest Energy Partners, L.P. and Oneok Partners, L.P. In processing and marketing NGLs, Enogex competes against virtually all other gas processors extracting and selling NGLs in its market area.

Regulation

State regulation of natural gas gathering facilities generally includes various safety, environmental and nondiscriminatory rate and open access requirements and complaint-based rate regulation. Enogex may be subject to state common carrier, ratable take and common purchaser statutes. The common carrier and ratable take statutes generally require gatherers to carry, transport and deliver, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers that purchase gas to purchase without undue discrimination as to source of supply or producer. These statutes may have the effect of restricting Enogex's right to decide with whom it contracts to purchase natural gas or, as an owner of gathering facilities, to decide with whom it contracts to purchase or gather natural gas.

Oklahoma and Texas have each adopted a form of complaint-based regulation of gathering operations that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering open access and rate discrimination. Texas has also adopted a complaint based regulation (H.B. 1920), known as the Lost and Unaccounted for Gas ("LUG") Bill. The LUG Bill expands the types of information that can be requested and gives the Texas Railroad Commission the authority to make determinations and issue orders for purposes of preventing waste in specific situations. To date, neither the gathering nor LUG regulations have had a significant impact on Enogex's operations in Oklahoma or Texas. However, Enogex cannot predict what effect, if any, either of these regulations might have on its gathering operations in Oklahoma or Texas in the future.

Enogex's gathering operations could be adversely affected should they be subject in the future to the application of state or Federal regulation of rates and services. Enogex's gathering operations could also be subject to additional safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. Enogex cannot predict what effect, if any, such changes might have on its operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Recent System Expansions

Over the past several years, Enogex has initiated multiple organic growth projects. Currently, in Enogex's gathering and processing business, organic growth capital expenditures are focused on expansions on the east side of Enogex's gathering system, primarily in the Woodford Shale play in southeastern Oklahoma and on the west side of Enogex's gathering system, primarily in the Granite Wash play, Woodford Shale play and Atoka play in western Oklahoma and the Granite Wash play and Atoka play in the Wheeler County, Texas area, which is located in the Texas Panhandle.

Southeastern Oklahoma / East Side Expansions

Enogex is expanding in the Woodford Shale play and has several projects either completed or scheduled for completion in 2009 and 2010. For example, in December 2006, Enogex entered into a joint venture arrangement with Pablo Gathering, LLC, a subsidiary of Pablo Energy II, LLC, a Texas-based exploration and production company, which resulted in the formation of Atoka. Atoka constructed, owns and/or operates a gathering system and processing plant and related facilities relating to production in certain areas in southeastern Oklahoma. The gathering system and processing plant were placed in service during the third quarter of 2007. Enogex owns a 50 percent membership interest in Atoka and acts as the managing member and operator of the facilities owned by the joint venture. The joint venture plans to expand its gathering pipeline infrastructure in order to accommodate additional production in the area. The capital expenditures associated with the pipeline expansion of Atoka are expected to be approximately $7 million.

In February 2008, Enogex completed construction of a 20-mile pipeline project that connected Enogex's Hughes, Coal and Pittsburgh County gathering system with the 30-inch Enogex mainline pipeline to Bennington, Oklahoma, and the 24-inch Enogex mainline pipeline to Wilburton, Oklahoma. The gathering project created additional gathering capacity of 75 MMcf/d for customers desiring low-pressure services. The pipeline is complemented by approximately 16,000 horsepower of new gathering compression which was completed in the third quarter of 2008. Also, in June 2009, Enogex added approximately 16 miles of 20-inch steel pipe to its system with throughput capacity of approximately 300 MMcf/d. The capital expenditures associated with these projects were approximately $68 million.

Enogex plans to construct a new compressor station in Coal County, Oklahoma, as well as approximately 10 miles of gathering pipe and related treating facilities. The station would be designed to accommodate up to 6,700 horsepower of low pressure compression and would be supported by approximately five miles of 20-inch steel pipe and five miles of 12-inch steel pipe. The new compressor station would also include the lease or possible purchase of associated gas treating facilities for the incremental gas in this area. The initial 2,700 horsepower at the compressor station, and the gathering pipe, are expected to be completed in February 2010, with an incremental 2,700 horsepower expected to be in service by April 2010. The capital expenditures for this construction are expected to be between approximately $18 million and $25 million depending on whether Enogex leases or purchases the equipment.

Texas Panhandle / West Side Expansions

In August 2006, Enogex completed a project to expand its gathering pipeline capacity in the Granite Wash play and Atoka play in the Wheeler County, Texas area of the Texas Panhandle that has allowed Enogex to benefit from growth opportunities in that marketplace. Since the pipeline was put in service, Enogex has completed the construction of five new gas gathering compressor stations totaling approximately 26,500 horsepower of compression, and several miles of gathering pipe, including a new 16-inch line that extends the original pipeline project an additional 20 miles to the west. In August 2009, Enogex added another 8,000 horsepower of low pressure compression in Wheeler County, Texas. The capital expenditures associated with the additional horsepower of low pressure compression were approximately $18 million.

In order to accommodate the increased drilling activity in Canadian County, Oklahoma, Enogex completed construction of approximately six miles of 12-inch steel pipe and another 2,800 horsepower of compression capacity to its Grandview gathering project in 2009. The capital expenditures associated with the additional pipe and compression capacity were approximately $8 million.

Enogex completed construction of a new 120 MMcf/d cryogenic plant equipped with electric compression near Clinton, Oklahoma. This plant was placed in service in late October 2009 and is processing new gas developments in the area. In support of this plant, Enogex has installed approximately 15 miles of gathering pipe, 2.5 miles of transmission pipe and 10,000 horsepower of inlet compression, as well as other system upgrades. The capital expenditures associated with these projects were approximately $77 million.

As additional support for the strong production needs surrounding Enogex's new Clinton plant, Enogex plans to build an additional six miles of 16-inch high pressure gathering pipe and construct a new compressor station designed to handle 6,700 horsepower of single-stage compression. The initial 4,000 horsepower at the compressor station, and the high pressure gathering pipe, are expected to be in service in August 2010. The capital expenditures for this initial stage of the construction are expected to be approximately $14 million.

Enogex is planning to further expand its gathering infrastructure in 2010 in the Wheeler County, Texas area with the construction of approximately nine miles of 10-inch steel pipe and seven miles of 16-inch steel pipe, as well as the addition of approximately 2,700 horsepower of compression. The gathering pipelines are expected to be in service in May 2010, while the compression is expected to be operational by July 2010. The capital expenditures associated with this project are expected to be approximately $12 million.

Enogex is planning construction of approximately 26 miles of 16-inch steel pipe and five miles of 8-inch steel pipe located in Washita and Custer counties in Oklahoma. This project will provide additional high pressure gathering capacity to active producers in this growth area. This project is expected to be in service in September 2010. The capital expenditures associated with this project are expected to be approximately $19 million.

Enogex Additional Processing Capacity

In the fourth quarter of 2009, Enogex began taking delivery of components of a cryogenic processing plant which, when installed, will be expected to add another 120 MMcf/d of processing capacity to Enogex's system. The capital expenditures associated with the purchase of the new processing cryogenic plant are expected to be approximately $16 million and exclude any expenditures for installation and ancillary equipment.

Safety and Health Regulation

Certain of Enogex's facilities are subject to Title 49 CFR Transportation Parts 191, 192, 195 and 199, including the Pipeline Safety Improvement Act of 2002 ("PSIA") and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 ("PIPES"). The Pipeline Hazardous Materials Safety Administration ("PHMSA") regulates safety requirements in the design, construction, operation and maintenance of applicable natural gas and hazardous liquid pipeline facilities. Both the PSIA and the PIPES require mandatory inspections and enforcement for all U.S. hazardous liquid and natural gas transportation pipelines, including some gathering lines in high population areas. The DOT has developed regulations implementing the PSIA that require pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in high-consequence areas where threats pose the greatest risk to people and their property.

States may be preempted by Federal law from solely regulating pipeline safety but may assume responsibility for enforcing Federal intrastate pipeline regulations and inspection of intrastate pipelines. In the state of Oklahoma, the OCC's Transportation Division, acting through the Pipeline Safety Department, administers the OCC's intrastate regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline. The OCC develops regulations and other approaches to assure safety in design, construction, testing, operation, maintenance and emergency response to pipeline facilities. The OCC derives its authority over intrastate pipeline operations through state statutes and certification agreements with the DOT. A similar regime for safety regulation is in place in Texas and administered by the Texas Railroad Commission. Enogex's natural gas pipelines have inspection and audit programs designed to maintain compliance with pipeline safety and pollution control requirements.

In addition, Enogex is subject to a number of Federal and state laws and regulations, including OSHA and comparable state statutes, whose purpose is to protect the safety and health of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in Enogex's operations and that this information be provided to employees, state and local government authorities and citizens. Enogex is also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Enogex has an internal program of inspection designed to monitor and enforce compliance with worker safety and health requirements. Enogex believes that it is in material compliance with all applicable laws and regulations relating to worker safety and health.

MARKETING - - OERI

General

OERI focuses on serving customers along the natural gas value chain, from producers to end-users, by purchasing natural gas from suppliers and reselling to pipelines, local distribution companies and end-users, including the electric generation sector. The geographic scope of marketing efforts has been focused largely in the mid-continent area of the United States. These markets are natural extensions of OERI's business on the Enogex system. OERI contracts for pipeline capacity with Enogex and other pipelines to access multiple interconnections with the interstate pipeline system network that moves natural gas from the production basins primarily in the south central United States to the major consumption areas in Chicago, New York and other north central and mid-Atlantic regions of the United States.

OERI primarily participates in both intermediate-term markets (less than three years) and short-term "spot" markets for natural gas. Although OERI continues to increase its focus on intermediate-term sales, short-term sales of natural gas are expected to continue to play a critical role in the overall strategy because they provide an important source of market intelligence as well as an important portfolio balancing function. OERI's average daily sales volumes decreased from approximately 0.6 Bcf in 2008 to approximately 0.4 Bcf in 2009. This reflects selective deal execution to assure adequate margin in light of credit and other risks in the current commodity price and credit environment. OERI's risk management skills afford its customers the opportunity to tailor the risk profile and composition of their natural gas portfolio. The Company follows a policy of hedging price risk on gas purchases or sales contracts entered into by OERI by buying and selling natural gas futures contracts on the New York Mercantile Exchange futures exchange and other derivatives in the over-the-counter market, subject to daily and monthly trading stop loss limits of $2.5 million and daily value-at-risk limits of $1.5 million in accordance with corporate policies.

On January 1, 2008, Enogex distributed the stock of OERI to OGE Energy. Enogex has historically utilized, and expects to continue to utilize, OERI for natural gas marketing, hedging, risk management and other related activities. For the years ended December 31, 2009, 2008 and 2007, OERI recorded revenues from Enogex of approximately $45.4 million, $41.9 million and $95.2 million, respectively, for the sale, at market rates, of natural gas. For the years ended December 31, 2009, 2008 and 2007, Enogex recorded revenues from OERI of approximately $165.5 million, $307.2 million, and $304.3 million, respectively, for the sale, at market rates, of natural gas. Enogex has paid, and expects to continue to pay, certain fees to OERI for providing natural gas marketing, hedging, risk management and other related services. OERI pays Enogex a fee for certain back office functions and administrative services.

Competition

OERI competes with major integrated oil companies, commercial banks, national and local natural gas marketers, distribution companies and marketing affiliates of interstate and intrastate pipelines in marketing natural gas. Competition for both natural gas supplies and natural gas sales is based primarily on reputation, accuracy, flexibility, products offered, credit support, the availability to transport gas to high-demand markets and the ability to obtain a satisfactory price for the natural gas.

For the year ended December 31, 2009, approximately 61.8 percent of OERI's service volumes were with electric utilities, local gas distribution companies, pipelines and producers, of which approximately 36.8 percent was with affiliates of OERI. The remaining 38.2 percent of service volumes were to marketers, municipals, cooperatives and industrials. At December 31, 2009, approximately 69.6 percent of the payment exposure was to companies having investment grade ratings with Standard & Poor's Ratings Services ("Standard & Poor's") and approximately 2.6 percent was to companies having less than investment grade ratings. The remaining 27.8 percent of OERI's exposure is with privately held companies, municipals or cooperatives that were not rated by Standard & Poor's. OERI applies internal credit analyses and policies to these non-rated companies.

Regulation

The price at which OERI buys and sells natural gas and NGLs is currently not subject to Federal regulation and, for the most part, is not subject to state regulation. However, OERI is required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission ("CFTC"). The FERC and CFTC hold substantial enforcement authority under the anti-market manipulation laws and regulations, including the ability to assess civil penalties of up to $1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should OERI violate the anti-market manipulation laws and regulations, it could also be subject to related third party damage claims by, among other, marketers, royalty owners and taxing authorities.

ENVIRONMENTAL MATTERS

General

The activities of OG&E and Enogex are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators, regulating future construction activities to avoid endangered species or enjoining some or all of the operations of facilities deemed in noncompliance with permits issued pursuant to such environmental laws and regulations. In most instances, the applicable regulatory requirements relate to water and air pollution control or solid waste management measures. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes can impose burdensome liability for costs required to clean up and restore sites where substances or wastes have been disposed or otherwise released into the environment. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment. OG&E and Enogex handle some materials subject to the requirements of the Federal Resource Conservation and Recovery Act and the Federal Water Pollution Control Act of 1972, as amended ("Federal Clean Water Act") and comparable state statutes, prepare and file reports and documents pursuant to the Toxic Substance Control Act and the Emergency Planning and Community Right to Know Act and obtain permits pursuant to the Federal Clean Air Act and comparable state air statutes.

OG&E and Enogex believe that their operations are in substantial compliance with applicable environmental laws and regulations. The trend in environmental regulation, however, is to place more restrictions and limitations on activities that may affect the environment. For example, as discussed below, in 2009, the EPA adopted a finding that greenhouse gases contribute to pollution and the EPA proposed rules related to the control of greenhouse gas emissions. OG&E and Enogex cannot assure that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause it to incur significant costs. Approximately $3.5 million of the Company's capital expenditures budgeted for 2010 are to comply with environmental laws and regulations, of which approximately $1.9 million and $1.6 million are related to OG&E and Enogex, respectively. Approximately $3.9 million of the Company's capital expenditures budgeted for 2011 are to comply with environmental laws and regulations, of which approximately $2.3 million and $1.6 million are related to OG&E and Enogex, respectively. It is estimated that OG&E's and Enogex's total expenditures for capital, operating, maintenance and other costs associated with environmental quality will be approximately $20.9 million and $5.7 million, respectively, in 2010 as compared to approximately $19.9 million and $4.0 million, respectively, in 2009. Management continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position it in a competitive market. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations" and Note 13 of Notes to Consolidated Financial Statements for a discussion of environmental matters, including the impact of existing and proposed environmental legislation and regulations.

Hazardous Waste

OG&E's and Enogex's operations generate hazardous wastes that are subject to the Federal Resource Conservation and Recovery Act of 1976 ("RCRA") as well as comparable state laws which impose detailed requirements for the handling, storage, treatment and disposal of hazardous waste.

For OG&E, these laws impose strict "cradle to grave" requirements on generators regarding their treatment, storage and disposal of hazardous waste. OG&E routinely generates small quantities of hazardous waste throughout its system that include, but are not limited to, waste paint, spent solvents, rechargeable batteries and mercury-containing lamps. These wastes are treated, stored and disposed off-site at facilities that are permitted to manage them. Occasionally, larger quantities of hazardous wastes are generated as a result of power generation-related activities and these larger quantities are managed either on-site or off-site. Nevertheless, through its waste minimization efforts, the majority of OG&E's facilities remain conditionally exempt small quantity generators of hazardous waste.

For Enogex, RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other waste associated with the exploration, development or production of crude oil and natural gas. However, these oil and gas exploration and production wastes may still be regulated under state law or the less stringent solid waste requirements of RCRA. Moreover, ordinary industrial waste such as paint waste, waste solvents and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

In December 2008, an impoundment used for the disposal of coal ash by a coal-fired power plant in Kingston, Tennessee failed, releasing more than five million cubic yards of ash onto adjacent land and into a nearby river. Shortly thereafter, the EPA announced its intention to avert similar incidents by promulgating rules to regulate coal ash by the end of 2009 pursuant to its authority under the RCRA. However, in December 2009, the EPA announced that the deadline for promulgating those rules had been extended indefinitely due to the complexity of the technical analyses involved in the rulemaking process. Thus, the extent to which the EPA intends to regulate coal ash is uncertain at this time. At issue is whether the EPA intends to regulate coal ash as a hazardous waste pursuant to Subtitle C of the RCRA and the impact such regulation will have on its future disposal and beneficial use insofar as OG&E is concerned. OG&E's coal-fired power plants do not dispose of coal ash on-site. Instead, the ash is commercially disposed off-site or is marketed for a variety of beneficial uses including those related to the cement/concrete manufacturing and road construction industries. Because of the uncertainty surrounding the EPA's decision on how coal ash will be regulated, the financial impact on the Company is uncertain at this time.

Site Remediation

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA") (also known as "Superfund") and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and companies that disposed or arranged for disposal of hazardous substances at offsite locations such as landfills. CERCLA authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Because OG&E and Enogex utilize various products and generate wastes that either are or otherwise contain CERCLA hazardous substances, OG&E and Enogex could be subject to burdensome liability for the costs of cleaning up and restoring sites where those substances have been released to the environment. At this time, it is not anticipated that any associated liability will cause any significant impact to OG&E or Enogex.

Enogex currently owns or leases, and has in the past owned or leased, numerous properties that for many years have been used for the measurement, gathering, transportation, compression, processing and storage of natural gas and NGLs. Although Enogex used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such substances have been taken for disposal. In fact, there is evidence that petroleum spills or releases have occurred at some of the properties owned or leased by Enogex. In addition, some of these properties have been operated by third parties or by previous owners whose treatment and disposal or release of petroleum hydrocarbon or wastes was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, Enogex could be required to remove previously disposed wastes (including waste disposed of by prior owners or operators) or remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historic activities or spills).

Air Emissions

OG&E's and Enogex's operations are subject to the Federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including electric generating units, natural gas processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that OG&E and Enogex obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, install emission control equipment or subject OG&E and Enogex to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. OG&E and Enogex likely will be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations" for a discussion of potentially significant environmental capital expenditures related to air emissions particularly as it relates to regional haze.

Water Discharges

OG&E's and Enogex's operations are subject to the Federal Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and Federal waters. The discharge of pollutants, including discharges resulting from a spill or leak incident, is prohibited unless authorized by a permit or other agency approval. The Federal Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Any unpermitted release of pollutants from OG&E's and Enogex's power plants, pipelines or facilities could result in administrative, civil and criminal penalties as well as significant remedial obligations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations" for a discussion of water intake matters.

Climate Change

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. Other nations have already agreed to regulate emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol," an international treaty pursuant to which participating countries (not including the United States) have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. At the end of 2009, an international conference to develop a successor to the Kyoto Protocol issued a document known as the Copenhagen Accord. Pursuant to the Copenhagen Accord, the United States submitted a greenhouse gas emission reduction target of 17 percent compared to 2005 levels. The U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, several states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases. For instance, at least nine states in the Northeast (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York and Vermont) and five states in the West (Arizona, California, New Mexico, Oregon and Washington) have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA is taking steps to regulate greenhouse gas emissions from mobile sources (such as cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The enactment of climate control laws or regulations that restrict emissions of greenhouse gases in areas in which OG&E and Enogex conduct business could have an adverse effect on their operations and demand for their services or products. OG&E reports quarterly its carbon dioxide emissions from generating units subject to the Federal Acid Rain Program and is continuing to evaluate various options for reducing, avoiding, off-setting or sequestering its carbon dioxide emissions. Sulfur hexafluoride and methane are also characterized by the EPA as greenhouse gases. OG&E is a partner in the EPA Sulfur Hexafluoride Voluntary Reduction Program and Enogex is a partner in the EPA Natural Gas STAR Program, both are voluntary programs to reduce emissions of greenhouse gases.

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

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

On December 15, 2009, the EPA published their finding that greenhouse gases contribute to air pollution that may endanger public health or welfare. Although the endangerment finding is being made in the context of greenhouse gas emissions from new motor vehicles, the finding is likely to result in other forms of regulation. Numerous petitions are pending at the EPA from various state and environmental groups seeking regulation of a variety of mobile sources (*i.e.*, trucks, airplanes, ships, boats, equipment, etc.) and stationary sources. With the endangerment finding issued, the EPA is likely to begin acting on these petitions in 2010. Additionally, on December 2, 2009 the Center for Biological Diversity announced a petition with the EPA seeking promulgation of a greenhouse gas National Ambient Air Quality Standard ("NAAQS").

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

FINANCE AND CONSTRUCTION

Future Capital Requirements

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 “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Requirements” for a discussion of the Company’s capital requirements.

Capital Expenditures

The Company’s consolidated estimates of capital expenditures are approximately: 2010 - $660 million, 2011 - $620 million, 2012 - $565 million, 2013 - $495 million, 2014 - $420 million and 2015 - $385 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:

	Total	Less than 1 year (2010)	1-3 years (2011-2012)	3-5 years (2013-2014)	More than 5 years
OG&E Base Transmission	$ 150	$ 45	$ 40	$ 40	$ 25
OG&E Base Distribution	1,320	235	430	435	220
OG&E Base Generation	205	30	70	70	35
OG&E Other	150	25	50	50	25
Total OG&E Base Transmission, Distribution, Generation and Other	1,825	335	590	595	305
OG&E Known and Committed Projects:					
Transmission Projects:					
Sunnyside-Hugo (345 kV)	120	30	90	---	---
Sooner-Rose Hill (345 kV)	65	10	55	---	---
Windspeed (345 kV)	25	25	---	---	---
Balanced Portfolio 3E Projects	300	10	170	120	---
Total Transmission Projects	510	75	315	120	---
Other Projects:					
Smart Grid Program (A)	230	40	120	60	10
System Hardening	35	20	15	---	---
OU Spirit	10	10	---	---	---
Other	30	20	10	---	---
Total Other Projects	305	90	145	60	10
Total OG&E Known and Committed Projects	815	165	460	180	10
Total OG&E (B)	2,640	500	1,050	775	315
Enogex (Base Maintenance and Known and Committed Projects)	355	135	85	90	45
OGE Energy and OERI	150	25	50	50	25
Total Consolidated	$ 3,145	$ 660	$ 1,185	$ 915	$ 385

(A) These capital expenditures are contingent upon OCC approval of OG&E’s Positive Energy Smart Grid program and are net of the Smart Grid $130 million grant approved by the DOE.
(B) The Base Capital Expenditure Plan above excludes any environmental expenditures associated with Best Available Retrofit Technology (“BART”) requirements due to the uncertainty regarding BART costs. As discussed in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations,” pursuant to a proposed regional haze agreement OG&E has agreed to install low nitrogen oxide (“NOX”) burners and related equipment at the three affected generating stations. Preliminary estimates indicate the cost will be approximately $100 million (plus or minus 30 percent). For further information, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations”.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in transmission assets, wind generation assets and at Enogex, will be evaluated based upon their impact upon achieving the Company’s financial objectives. The capital expenditure projections related to Enogex in the table above reflect base market conditions at February 17, 2010 and do not reflect the potential opportunity for a set of growth projects that could materialize.

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

On June 24, 2009, Enogex issued $200 million of 6.875% 5-year senior notes in a transaction exempt from the registration requirements of the Securities Act of 1933. Enogex applied a portion of the net proceeds from the sale of the new notes to pay the purchase price in a tender offer for its 8.125% notes due January 15, 2010 with the remainder of the net proceeds being used to repay a portion of Enogex's borrowings under its revolving credit agreement and for general corporate purposes. Pursuant to the tender offer, on July 23, 2009, Enogex purchased approximately $110.8 million principal amount of the 8.125% senior notes due January 15, 2010 and those repurchased notes were retired and cancelled.

On November 10, 2009, Enogex issued $250 million of 6.25% 10-year senior notes in a transaction exempt from the registration requirements of the Securities Act of 1933. Enogex applied the net proceeds from the sale of the new notes to repay borrowings under its revolving credit agreement, with any excess net proceeds being invested at the OGE Energy level. Enogex's permanent use of the net proceeds from this debt issuance was to repay a portion of the $289.2 million outstanding aggregate principal amount of Enogex's 8.125% senior notes, which matured on January 15, 2010. On January 15, 2010, the $289.2 million outstanding aggregate principal amount of Enogex's 8.125% senior notes was repaid.

Pension and Postretirement Benefit Plans

During each of 2009 and 2008, the Company made contributions to its pension plan of approximately $50.0 million to help ensure that the pension plan maintains an adequate funded status. During 2010, the Company may contribute up to $50.0 million to its pension plan. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Requirements" for a discussion of the Company's pension and postretirement benefit plans.

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 ("DRIP/DSPP") 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 capital expenditures until permanent financing is arranged.

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was approximately $175.0 million and $298.0 million at December 31, 2009 and 2008, respectively. The December 31, 2009 short-term debt balance of approximately $175.0 million is comprised entirely of outstanding commercial paper borrowings at OGE Energy. The December 31, 2008 short-term debt balance of approximately $298.0 million is comprised entirely of outstanding borrowings under OGE Energy's revolving credit agreement. At December 31, 2009, there were no outstanding borrowings under Enogex's revolving credit agreement. At December 31, 2008, Enogex had approximately $120.0 million in outstanding borrowings under its revolving credit agreement. Also, OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any time for a two-year period beginning January 1, 2009 and ending December 31, 2010. See Note 10 of Notes to the Consolidated Financial Statements for a discussion of the Company's short-term debt activity. The Company has approximately $58.1 million and $174.4 million of cash and cash equivalents at December 31, 2009 and 2008, respectively.

Registration Statement Filing

During the first half of 2010, the Company expects to file a Form S-3 Registration Statement to register debt and equity securities for sale by the Company and OG&E.

Expected Issuance of OG&E Long-Term Debt

OG&E expects to issue approximately $250 million of long-term debt in mid-2010, depending on market conditions, to fund capital expenditures, repay short-term borrowings and for general corporate purposes.

Common Stock

The Company expects to issue between approximately $12 million and $15 million in its DRIP/DSPP in 2010. See Note 8 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

EMPLOYEES

The Company and its subsidiaries had 3,363 employees at December 31, 2009.

ACCESS TO SECURITIES AND EXCHANGE COMMISSION FILINGS

The Company's web site address is *www.oge.com*. Through the Company's web site under the heading "Investor Relations", "SEC Filings," the Company makes available, free of charge, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Our Internet website and the information contained therein or connected thereto are not intended to be incorporated into this Form 10-K and should not be considered a part of this Form 10-K.

Item 1A. Risk Factors.

In the discussion of risk factors set forth below, unless the context otherwise requires, the terms "OGE Energy", "we", "our" and "us" refer to OGE Energy Corp., "OG&E" refers to our subsidiary Oklahoma Gas and Electric Company and "Enogex" refers to our subsidiary Enogex LLC and its subsidiaries. In addition to the other information in this Annual Report on Form 10-K and other documents filed by us and/or our subsidiaries with the SEC from time to time, the following factors should be carefully considered in evaluating OGE Energy and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by or on behalf of us or our subsidiaries. Additional risks and uncertainties not currently known to us or that we currently view as immaterial may also impair our business operations.

REGULATORY RISKS

Our profitability depends to a large extent on the ability of OG&E to fully recover its costs from its customers and there may be changes in the regulatory environment that impair its ability to recover costs from its customers.

We are subject to comprehensive regulation by several Federal and state utility regulatory agencies, which significantly influences our operating environment and OG&E's ability to fully recover its costs from utility customers. With rising fuel costs, recoverability of under recovered amounts from our customers is a significant risk. The utility commissions in the states where OG&E operates regulate many aspects of our utility operations including siting and construction of facilities, customer service and the rates that we can charge customers. The profitability of our utility operations is dependent on our ability to fully recover costs related to providing energy and utility services to our customers.

In recent years, the regulatory environments in which we operate have received an increased amount of public attention. It is possible that there could be changes in the regulatory environment that would impair our ability to fully recover costs historically absorbed by our customers. State utility commissions generally possess broad powers to ensure that the needs of the utility customers are being met. We cannot assure that the OCC, APSC and the FERC will grant us rate increases in the future or in the amounts we request, and they could instead lower our rates.

We are unable to predict the impact on our operating results from the future regulatory activities of any of the agencies that regulate us. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

OG&E's rates are subject to rate regulation by the states of Oklahoma and Arkansas, as well as by a Federal agency, whose regulatory paradigms and goals may not be consistent.

OG&E is currently a vertically integrated electric utility and most of its revenue results from the sale of electricity to retail customers subject to bundled rates that are approved by the applicable state utility commission and from the sale of electricity to wholesale customers subject to rates and other matters approved by the FERC.

OG&E operates in Oklahoma and western Arkansas and is subject to rate regulation by the OCC and the APSC, in addition to the FERC. Exposure to inconsistent state and Federal regulatory standards may limit our ability to operate profitably. Further alteration of the regulatory landscape in which we operate may harm our financial position and results of operations.

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

We are subject to extensive Federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife mortality, natural resources and health and safety that could, among other things, restrict or limit the output of certain facilities or the use of certain fuels required for the production of electricity and/or require additional pollution control equipment and otherwise increase costs. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future. For example, the EPA has proposed lowering the ambient standards for ozone and SO2. If these standards are adopted, reductions in emissions from OG&E's electric generating facilities could be required, which may result in significant capital and operating expenditures.

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

There also is growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation at the Federal level, actions at the state level, litigation relating to greenhouse gas emissions and pressure for greenhouse gas emission reductions from investor organizations and the international community. Recently, two Federal courts of appeal have reinstated nuisance-type claims against emitters of carbon dioxide, including several utility companies, alleging that such emissions contribute to global warming. Although the Company is not a defendant in either proceeding, additional litigation in Federal and state courts over these issues is expected.

OG&E reports quarterly its carbon dioxide emissions from its generating stations under the EPA's acid rain program and is continuing to evaluate various options for reducing, avoiding, off-setting or sequestering its carbon dioxide emissions. Additional reporting is required by a rule issued by the EPA in 2009, and the EPA has proposed rules that could regulate carbon dioxide emissions under the Federal Clean Air Act. For a further discussion of environmental matters that may affect the Company, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations" and "Environmental Laws and Regulations" in Note 13 of Notes to Consolidated Financial Statements. If legislation or regulations are passed at the Federal or state levels in the future requiring mandatory reductions of carbon dioxide and other greenhouse gases on generation facilities to address climate change, this could result in significant additional compliance costs that would affect our future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

We are subject to physical and financial risks associated with climate change.

There is a growing concern that emissions of greenhouse gases are linked to global climate change. Climate change creates physical and financial risk. Physical risks from climate change could include an increase in sea level and changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. OG&E's operations are not sensitive to potential future sea-level rise as it does not operate in coastal areas. However, OG&E's power delivery systems are vulnerable to damage from extreme weather events, such as ice storms, tornadoes and severe thunderstorms. These types of extreme weather events are common on the OG&E system, so OG&E includes storm restoration in its budgeting process as a normal business expense. To the extent the frequency of extreme weather events increases, this could increase OG&E's cost of providing service. OG&E's electric generating facilities are designed to withstand the effects of extreme weather events, however, extreme weather conditions increase the stress placed on such systems. If climate change results in temperature increases in OG&E's service territory, OG&E could expect increased electricity demand due to the increase in temperature and longer warm seasons. While this increase in demand could lead to increased energy consumption, it could also create a physical strain on OG&E's generating resources. At the same time, OG&E could face restrictions on the ability to meet that demand if, due to drought severity, there is a lack of sufficient water for use in cooling during the electricity generating process.

In addition to the above cited risks, to the extent that any climate change adversely affects the national or regional economic health through increased rates caused by the inclusion of additional regulatory imposed costs (carbon dioxide taxes or costs associated with additional regulatory requirements), the Company may be adversely impacted. A declining economy could adversely impact the overall financial health of the Company because of lack of load growth and decreased sales opportunities.

To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions.

Our business plan for OG&E calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits and modernizing existing infrastructure as well as other initiatives. Significant portions of OG&E’s facilities were constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements or to provide reliable operations. OG&E currently provides service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates we charge, we would not be able to recover the costs associated with our planned extensive investment. This could adversely affect our results of operations and financial position. While we may seek to limit the impact of any denied recovery by attempting to reduce the scope of our capital investment, there can no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

Our planned capital investment program coincides with a material increase in the historic prices of the fuels used to generate electricity. Many of our jurisdictions have fuel clauses that permit us to recover these increased fuel costs through rates without a general rate case. While prudent capital investment and variable fuel costs each generally warrant recovery, in practical terms our regulators could limit the amount or timing of increased costs that we would recover through higher rates. Any such limitation could adversely affect our results of operations and financial position.

The construction by Enogex of additions or modifications to its existing systems, and the construction of new midstream assets, involves numerous regulatory, environmental, political and legal uncertainties, many of which are beyond Enogex’s control and may require the expenditure of significant amounts of capital. These projects, once undertaken, may not be completed on schedule or at the budgeted cost, or at all. Moreover, Enogex’s revenues and cash flows may not increase immediately upon the expenditure of funds on a particular project. For instance, if Enogex expands an existing pipeline or constructs a new pipeline, the construction may occur over an extended period of time, and Enogex may not receive any material increases in revenues or cash flows until the project is completed. In addition, Enogex may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since Enogex is not engaged in the exploration for and development of natural gas, Enogex often does not have access to third-party estimates of potential reserves in areas to be developed prior to constructing facilities in those areas. To the extent Enogex relies on estimates of future production in deciding to construct additions to its systems, those estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating future production. As a result, new facilities may not be able to attract sufficient throughput to achieve expected investment return, which could adversely affect Enogex’s results of operations, consolidated financial position and cash flows. In addition, the construction of additions to existing gathering and transportation assets may require new rights-of-way prior to construction. Those rights-of-way to connect new natural gas supplies to existing gathering lines may be unavailable and Enogex may not be able to capitalize on attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, Enogex’s consolidated financial position, results of operations and cash flows could be adversely affected.

The regional power market in which OG&E operates has changing transmission regulatory structures, which may affect the transmission assets and related revenues and expenses.

OG&E currently owns and operates transmission and generation facilities as part of a vertically integrated utility. OG&E is a member of the SPP RTO and has transferred operational authority (but not ownership) of OG&E’s transmission facilities to the SPP RTO. The SPP RTO implemented a regional energy imbalance service market on February 1, 2007. OG&E has participated, and continues to participate, in the SPP energy imbalance service market to aid in the optimization of its physical assets to serve OG&E’s customers. OG&E has not participated in the SPP energy imbalance service market for any speculative trading activities. The SPP purchases and sales are not allocated to individual customers. OG&E records the hourly sales to the SPP at market rates in Operating Revenues and the hourly purchases from the SPP at market rates in Cost of Goods Sold in its Consolidated Financial Statements. OG&E’s revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operation and regulation by the FERC or the SPP RTO.

Increased competition resulting from restructuring efforts could have a significant financial impact on us and OG&E and consequently decrease our revenue.

We have been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes already have occurred and additional changes have been proposed to the wholesale electric market. Although retail restructuring efforts in Oklahoma and Arkansas have been postponed for the time being, if such efforts were renewed, retail competition and the unbundling of regulated energy service could have a significant financial impact on us due to possible impairments of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. Any such restructuring could have a significant impact on our consolidated financial position, results of operations and cash flows. We cannot predict when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on our consolidated financial position, results of operations or cash flows.

A change in the jurisdictional characterization of some of Enogex's assets by Federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of its assets, which may cause its revenues to decline and operating expenses to increase.

Enogex's natural gas gathering and intrastate transportation operations are generally exempt from the jurisdiction of the FERC under the Natural Gas Act of 1938, but the FERC regulation may indirectly impact these businesses and the markets for products derived from these businesses. The FERC's policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking and capacity release and its promotion of market centers, may indirectly affect intrastate markets. In recent years, the FERC has aggressively pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure that the FERC will continue to pursue these same objectives as it considers matters such as pipeline rates and rules and policies that may indirectly affect the intrastate natural gas transportation business.

Enogex's natural gas transportation and storage operations are subject to regulation by the FERC pursuant to Section 311 of the NGPA, which could have an adverse impact on its ability to establish transportation and storage rates that would allow it to recover the full cost of operating its transportation and storage facilities, including a reasonable return, and an adverse impact on its consolidated financial position, results of operations or cash flows.

The FERC has jurisdiction over transportation rates charged by Enogex for transporting natural gas in interstate commerce under Section 311 of the NGPA. Rates to provide such service must be "fair and equitable" under the NGPA and are subject to review and approval by the FERC at least once every three years. See Note 14 of Notes to Consolidated Financial Statements for a further discussion of Enogex's FERC Section 311 proceedings. There can be no assurance that the FERC will approve Enogex's requested rates.

Enogex's natural gas transportation, storage and gathering operations are subject to regulation by agencies in Oklahoma and Texas, and that regulation could have an adverse impact on its ability to establish rates that would allow it to recover the full cost of operating its facilities, including a reasonable return, and its consolidated financial position, results of operations or cash flows.

State regulation of natural gas transportation, storage and gathering facilities generally focuses on various safety, environmental and, in some circumstances, nondiscriminatory access requirements and complaint-based rate regulation. Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, Enogex's natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and services. Enogex's gathering operations could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. Additional rules and legislation pertaining to these matters are considered and, in some instances, adopted from time to time. We cannot predict what effect, if any, such changes might have on Enogex's operations, but Enogex could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect Enogex's business. Any such state regulation could have an adverse impact on Enogex's business and its consolidated financial position, results of operations or cash flows.

Enogex may incur significant costs and liabilities resulting from pipeline integrity programs and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, the DOT has adopted regulations requiring pipeline operators to develop integrity management programs for applicable pipelines. The regulations require operators to:

- identify potential threats to the public or environment, including "high consequence areas" on covered pipeline segments where a leak or rupture could do the most harm;

- develop a baseline plan to prioritize the assessment of a covered pipeline segment;
- gather data and identify and characterize applicable threats that could impact a covered pipeline segment;
- discover, evaluate and remediate problems in accordance with the program requirements;
- continuously improve all elements of the integrity program;
- continuously perform preventative and mitigation actions;
- maintain a quality assurance process and management-of-change process; and
- establish a communication plan that addresses safety concerns raised by the DOT and state agencies, including the periodic submission of performance documents to the DOT.

During 2009, Enogex incurred approximately $10.8 million of capital expenditures and operating costs for pipeline integrity management. Enogex currently estimates that it will incur capital expenditures and operating costs of approximately $34.2 million between 2010 and 2014 in connection with pipeline integrity management. The estimated capital expenditures and operating costs include Enogex's estimates for the assessment, remediation, prevention or other mitigation that may be determined to be necessary. At this time, we cannot predict the ultimate costs of its integrity management program and compliance with this regulation because those costs will depend on the number and extent of any repairs found to be necessary. Enogex will continue to assess, remediate and maintain the integrity of its pipelines. The results of these activities could cause Enogex to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

Events that are beyond our control have increased the level of public and regulatory scrutiny of our industry. Governmental and market reactions to these events may have negative impacts on our business, consolidated financial position, cash flows and access to capital.

As a result of accounting irregularities at public companies in general, and energy companies in particular, and investigations by governmental authorities into energy trading activities, public companies, including those in the regulated and unregulated utility business, have been under an increased amount of public and regulatory scrutiny and suspicion. The accounting irregularities have caused regulators and legislators to review current accounting practices, financial disclosures and relationships between companies and their independent auditors. The capital markets and rating agencies also have increased their level of scrutiny. We believe that we are complying with all applicable laws and accounting standards, but it is difficult or impossible to predict or control what effect these types of events may have on our business, consolidated financial position, cash flows or access to the capital markets. It is unclear what additional laws or regulations may develop, and we cannot predict the ultimate impact of any future changes in accounting regulations or practices in general with respect to public companies, the energy industry or our operations specifically. Any new accounting standards could affect the way we are required to record revenues, expenses, assets, liabilities and equity. These changes in accounting standards could lead to negative impacts on reported earnings or decreases in assets or increases in liabilities that could, in turn, affect our results of operations and cash flows.

We are subject to substantial utility and energy regulation by governmental agencies. Compliance with current and future utility and energy regulatory requirements and procurement of necessary approvals, permits and certifications may result in significant costs to us.

We are subject to substantial regulation from Federal, state and local regulatory agencies. We are required to comply with numerous laws and regulations and to obtain numerous permits, approvals and certificates from the governmental agencies that regulate various aspects of our businesses, including customer rates, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices and the operation of generating facilities. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from future regulatory activities of these agencies.

The Energy Policy Act of 2005 gave the FERC authority to establish mandatory electric reliability rules enforceable with significant monetary penalties. The FERC has approved the North American Electric Reliability Corporation ("NERC") as the Electric Reliability Organization for North America and delegated to it the development and enforcement of electric transmission reliability rules. It is the Company's intent to comply with all applicable reliability rules and expediently correct a violation should it occur. OG&E is subject to a NERC compliance audit every three years as well as periodic spot check audits and cannot predict the outcome of those audits.

OPERATIONAL RISKS

Our results of operations may be impacted by disruptions beyond our control.

We are exposed to risks related to performance of contractual obligations by our suppliers. We are dependent on coal for much of our electric generating capacity. We rely on suppliers to deliver coal in accordance with short and long-term contracts. We have certain coal supply contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal to us. The suppliers under these agreements may experience financial or technical problems that inhibit their ability to fulfill their obligations to us. In addition, the suppliers under these agreements may not be required to supply coal to us under certain circumstances, such as in the event of a natural disaster. Coal delivery may be subject to short-term interruptions or reductions due to various factors, including transportation problems, weather and availability of equipment. Failure or delay by our suppliers of coal deliveries could disrupt our ability to deliver electricity and require us to incur additional expenses to meet the needs of our customers. In addition, as agreements with our suppliers expire, we may not be able to enter into new agreements for coal delivery on equivalent terms.

Also, because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business due to a disruption or black-out caused by an event (severe storm, generator or transmission facility outage) on a neighboring system or the actions of a neighboring utility. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our consolidated financial position and results of operations.

Economic conditions could negatively impact our business.

Our operations are affected by local, national and worldwide economic conditions. The consequences of a prolonged recession could include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity could result in a decline in energy consumption, which could adversely affect our revenues and future growth. Instability in the financial markets, as a result of recession or otherwise, also could affect the cost of capital and our ability to raise capital.

Current economic conditions may be exacerbated by insufficient financial sector liquidity leading to potential increased unemployment, which could impact the ability of our customers to pay timely, increase customer bankruptcies, and could lead to increased bad debt. If such circumstances occur, we expect that commercial and industrial customers would be impacted first, with residential customers following.

We are subject to information security risks.

A security breach of our information systems could impact the reliability of the generation fleet and/or reliability of the transmission and distribution system or subject us to financial harm associated with theft or inappropriate release of certain types of operating or customer information. We cannot accurately assess the probability that a security breach may occur, despite the measures we have taken to prevent such a breach, and we are unable to quantify the potential impact of such an event.

Terrorist attacks, and the threat of terrorist attacks, have resulted in increased costs to our business. Continued hostilities in the Middle East or other sustained military campaigns may adversely impact our consolidated financial position, results of operations and cash flows.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the magnitude of the threat of future terrorist attacks on the electric utility and natural gas midstream industry in general, and on us in particular, cannot be known. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of supplies and markets for our products, and the possibility that our infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than existing insurance coverage.

Enogex does not own all of the land on which its pipelines and facilities are located, which could disrupt its operations.

Enogex does not own all of the land on which its pipelines and facilities have been constructed, and it is therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if it does not have valid rights-of-way or if such rights-of-way lapse or terminate. Enogex obtains the rights to construct and operate its pipelines on land owned by third parties and governmental agencies sometimes for a specific period of time. A loss of these rights, through Enogex's inability to renew right-of-way contracts or otherwise, could cause Enogex to cease operations temporarily or permanently on the affected land, increase costs related to the construction and continuing operations elsewhere, reduce its revenue and impair its cash flows.

Weather conditions such as tornadoes, thunderstorms, ice storms, wind storms, as well as seasonal temperature variations may adversely affect our consolidated financial position, results of operations and cash flows.

Weather conditions directly influence the demand for electric power. In OG&E's service area, demand for power peaks during the hot summer months, with market prices also typically peaking at that time. As a result, overall operating results may fluctuate on a seasonal and quarterly basis. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. Unusually mild weather in the future could reduce our revenues, net income, available cash and borrowing ability. Severe weather, such as tornadoes, thunderstorms, ice storms and wind storms, may cause outages and property damage which may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned, as described above, would be particularly burdensome during a peak demand period.

Natural gas and NGLs prices are volatile, and changes in these prices could negatively affect Enogex's and OERI's results of operations and cash flows.

Enogex's and OERI's results of operations and cash flows could be negatively affected by adverse movements in the prices of natural gas and NGLs depending on factors that are beyond our control. These factors include demand for these commodities, which fluctuates with changes in market and economic conditions and other factors, including the impact of seasonality and weather, general economic conditions, the level of domestic and offshore natural gas production and consumption, the availability of imported natural gas, liquified natural gas and NGLs, actions taken by foreign oil and gas producing nations, the availability of local, intrastate and interstate transportation systems, the availability and marketing of competitive fuels, the impact of energy conservation efforts, technological advances affecting energy consumption and the extent of governmental regulation and taxation.

Enogex's keep-whole natural gas processing arrangements, which constituted approximately six percent of its gross margin and accounted for approximately 35 percent of its natural gas processed volumes during 2009, expose it to fluctuations in the pricing spreads between NGLs prices and natural gas prices. Keep-whole processing arrangements generally require a processor of natural gas to keep its shippers whole on a Btu basis by replacing the Btu's of the NGLs extracted from the production stream with Btu's of natural gas. Therefore, if natural gas prices increase and NGLs prices do not increase by a corresponding amount, the processor has to replace the Btu's of natural gas at higher prices and processing margins are negatively affected.

Enogex's percent-of-proceeds and percent-of-liquids natural gas processing agreements constituted approximately seven percent of its gross margin and accounted for approximately 45 percent of its natural gas processed volumes during 2009. Under these arrangements, Enogex generally gathers raw natural gas from producers at the wellhead, transports the gas through its gathering system, processes the gas and sells the processed gas and/or NGLs at prices based on published index prices. The price paid to producers is based on an agreed percentage of the proceeds of the sale of processed natural gas, NGLs or both or the expected proceeds based on an index price. Enogex refers to contracts in which it shares in specified percentages of the proceeds from the sale of natural gas and NGLs as percent-of-proceeds arrangements and in which it receives proceeds from the sale of NGLs or the NGLs themselves as compensation for its processing services as percent-of-liquids arrangements. These arrangements expose Enogex to risks associated with the price of natural gas and NGLs.

At any given time, Enogex's overall portfolio of processing contracts may reflect a net short position in natural gas (meaning that Enogex was a net buyer of natural gas) and a net long position in NGLs (meaning that Enogex was a net seller of NGLs). As a result, Enogex's margins could be negatively impacted to the extent the price of NGLs decreases in relation to the price of natural gas.

Because of the natural decline in production from existing wells connected to Enogex's systems, Enogex's success depends on its ability to gather new sources of natural gas, which depends on certain factors beyond its control. Any decrease in supplies of natural gas could adversely affect Enogex's business and results of operations and cash flows.

Enogex's gathering and transportation systems are connected to or dependent on the level of production from natural gas wells, from which production will naturally decline over time. As a result, Enogex's cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on its gathering and transportation systems and the asset utilization rates at its natural gas processing plants, Enogex must continually obtain new natural gas supplies. The primary factors affecting Enogex's ability to obtain new supplies of natural gas and attract new customers to its assets depends in part on the level of successful drilling activity near these systems, Enogex's ability to compete for volumes from successful new wells and Enogex's ability to expand capacity as needed. If Enogex is not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells, throughput on its gathering, processing and transportation facilities would decline, which could have a material adverse effect on its business, results of operations and cash flows.

Enogex's businesses are dependent, in part, on the drilling decisions of others.

All of Enogex's businesses are dependent on the continued availability of natural gas production. Enogex does not have control over the level of drilling activity in the areas of its operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. The primary factor that impacts drilling decisions is natural gas prices. Natural gas prices reached relatively high levels in mid-2008 due to the impact of rising demand for natural gas but have returned to the near $4.50 per MMBtu level due to a rapid decline in demand for natural gas. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by Enogex's gathering, processing and transportation facilities, which would lead to reduced utilization of these assets. Other factors that impact production decisions include producers' capital budgets, access to credit, the ability of producers to obtain necessary drilling and other governmental permits, costs of steel and other commodities, geological considerations, demand for hydrocarbons, the level of reserves, other production and development costs and regulatory changes. Because of these factors, even if new natural gas reserves are discovered in areas served by Enogex's assets, producers may choose not to develop those reserves.

The Company engages in commodity hedging activities to minimize the impact of commodity price risk, which may have a volatile effect on its earnings and cash flows.

The Company is exposed to changes in commodity prices in its operations. To minimize the risk of commodity prices, the Company may enter into physical forward sales or financial derivative contracts to hedge purchase and sale commitments, fuel requirements, contractual long/short obligations, keep-whole positions, percent-of-liquids positions and inventories of natural gas.

Enogex has instituted a hedging program that is intended to reduce the commodity price risk associated with Enogex's keep-whole and percent-of-liquids arrangements. At December 31, 2009, Enogex had hedged a majority of its expected non-ethane NGLs volumes attributable to these arrangements, along with the natural gas MMBtu equivalent for keep-whole volumes, for 2010 and 2011. At December 31, 2009, Enogex had not hedged any of its expected ethane volumes attributable to these arrangements, along with the natural gas MMBtu equivalent for keep-whole volumes. Enogex has the option to reject ethane if processing it is not economical. Management will continue to evaluate whether to enter into any new hedging arrangements, and there can be no assurance that Enogex will enter into any new hedging arrangements. Also, Enogex may seek in the future to further limit its exposure to changes in natural gas and NGLs commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms. To the extent Enogex hedges its commodity price and interest rate exposures, Enogex may forego the benefits that otherwise would be experienced if commodity prices or interest rates were to change in Enogex's favor. In addition, even though management monitors Enogex's hedging activities, these activities can result in substantial losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect or ineffective, or the hedging policies and procedures are not followed or do not work as planned.

Enogex depends on certain key natural gas producer customers for a significant portion of its supply of natural gas and NGLs. The loss of, or reduction in volumes from, any of these customers could result in a decline in its consolidated financial position, results of operations or cash flows.

Enogex relies on certain key natural gas producer customers for a significant portion of its natural gas and NGLs supply. During 2009, Chesapeake Energy Marketing Inc., Devon Gas Services, L.P., Apache Corporation, BP America Production Company and Samson Resources Company accounted for approximately 52.4 percent of Enogex's natural gas and NGLs supply. The loss of the natural gas and NGLs volumes supplied by these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could have a material adverse effect on Enogex's consolidated financial position, results of operations and cash flows.

Enogex depends on two customers for a significant portion of its firm intrastate transportation and storage services. The loss of, or reduction in volumes from, either of these customers could result in a decline in Enogex's transportation and storage services and its consolidated financial position, results of operations or cash flows.

Enogex provides firm intrastate transportation and storage services to several customers on its system. Enogex's major customers are OG&E and PSO, which is the second largest electric utility in Oklahoma and serves the Tulsa market. As part of the no-notice load following contract with OG&E, Enogex provides natural gas storage services for OG&E. Enogex provides gas transmission delivery services to all of PSO's natural gas-fired electric generation facilities in Oklahoma under a firm intrastate transportation contract. In 2009, 2008 and 2007, revenues from Enogex's firm intrastate transportation and storage contracts were approximately $116.8 million, $104.4 million and $103.9 million, respectively, of which approximately $47.5 million, $47.5 million and $47.4 million, respectively, was attributed to OG&E and approximately $15.3 million, $15.3 million and $13.3 million, respectively, was attributed to PSO. Enogex's current contract with PSO expires January 1, 2013, unless extended. The stated term of Enogex's current contract with OG&E expired April 30, 2009, but the contract will remain in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 180 days prior to the commencement of the next succeeding annual period. Because neither party provided notice of termination 180 days prior to May 1, 2010, the contract will remain in effect at least through April 30, 2011. The loss of all or even a portion of the intrastate transportation and storage services for either of these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could have a material adverse effect on Enogex's consolidated financial position, results of operations and cash flows.

If third-party pipelines and other facilities interconnected to Enogex's gathering, processing or transportation facilities become partially or fully unavailable, Enogex's revenues and cash flows could be adversely affected.

Enogex depends upon third-party natural gas pipelines to deliver gas to, and take gas from, its transportation system. Enogex also depends on third-party facilities to transport and fractionate NGLs that it delivers to the third party at the tailgates of its processing plants. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. Since Enogex does not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within Enogex's control. If any of these third-party pipelines or other facilities become partially or fully unavailable, Enogex's revenues and cash flows could be adversely affected.

Enogex's industry is highly competitive, and increased competitive pressure could adversely affect its consolidated financial position, results of operations or cash flows.

Enogex competes with similar enterprises in its respective areas of operation. Some of these competitors are large oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of natural gas and NGLs than Enogex. Some of these competitors may expand or construct gathering, processing, transportation and storage systems that would create additional competition for the services Enogex provides to its customers. In addition, Enogex's customers who are significant producers of natural gas may develop their own gathering, processing, transportation and storage systems in lieu of using Enogex's. Enogex's ability to renew or replace existing contracts with its customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of its competitors and customers. All of these competitive pressures could have a material adverse effect on Enogex's consolidated financial position, results of operations and cash flows.

Gathering, processing, transporting and storing natural gas involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, Enogex's operations and financial results could be adversely affected.

Gathering, processing, transporting and storing natural gas involves many hazards and operational risks, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by tornadoes, floods, earthquakes, fires and other natural disasters and acts of terrorism;
- inadvertent damage from third parties, including construction, farm and utility equipment;
- leaks of natural gas, NGLs and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities; and
- fires and explosions.

These and other risks could result in substantial losses due to personal injury and loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of Enogex's related operations. Enogex's insurance is currently provided under the Company's insurance programs. Enogex is not fully insured against all risks inherent to its business. Enogex is not insured against all environmental accidents that might occur, which may include toxic tort claims. In addition, Enogex may not be able to maintain or obtain insurance of the type and amount desired at reasonable rates. Moreover, in some instances, significant claims by the Company may limit or eliminate the amount of insurance proceeds available to Enogex. As a result of market conditions, premiums and deductibles for certain of the Company's insurance policies have increased substantially, and could escalate further. In some instances, insurance could become unavailable or available only for reduced amounts of coverage. If a significant accident or event occurs that is not fully insured, it could adversely affect Enogex's operations and financial results.

FINANCIAL RISKS

Market performance, increased retirements, changes in retirement plan regulations and increasing costs associated with our defined benefit retirement plans, health care plans and other employee-related benefits may adversely affect our results of operations, consolidated financial position or liquidity.

We have a qualified defined benefit retirement plan ("Pension Plan") that covers substantially all of our employees hired before December 1, 2009. In October 2009, our Pension Plan and our qualified defined contribution retirement plan ("401(k) Plan") were amended, effective December 31, 2009, to offer a one-time irrevocable election for eligible employees, depending on their hire date, to select a future retirement benefit combination from our Pension Plan and our 401(k) Plan. Also, effective December 1, 2009, our Pension Plan is no longer being offered to future employees of the Company. We also have defined benefit postretirement plans that cover substantially all of our employees. Assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions with respect to the defined benefit retirement and postretirement plans have a significant impact on our earnings and funding requirements. Based on our assumptions at December 31, 2009, we expect to continue to make future contributions to maintain required funding levels. It is our practice to also make voluntary contributions to maintain more prudent funding levels than minimally required. These amounts are estimates and may change based on actual stock market performance, changes in interest rates and any changes in governmental regulations.

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the "Pension Protection Act") into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Many of the changes enacted as part of the Pension Protection Act were required to be implemented as of the first plan year beginning in 2008. The Company has implemented all of the required changes as part of the Pension Protection Act as discussed in Note 11 of Notes to Consolidated Financial Statements.

All employees hired prior to February 1, 2000 participate in defined benefit postretirement plans. If these employees retire when they become eligible for retirement over the next several years, or if our plan experiences adverse market returns on its investments, or if interest rates materially fall, our pension expense and contributions to the plans could rise substantially over historical levels. The timing and number of employees retiring and selecting the lump-sum payment option could result in pension settlement charges that could materially affect our results of operations if we are unable to recover these costs through our electric rates. In addition, assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions, including projected retirements, have a significant impact on our results of operations and consolidated financial position. Those factors are outside of our control.

In addition to the costs of our retirement plans, the costs of providing health care benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. The increasing costs and funding requirements with our defined benefit retirement plan, health care plans and other employee benefits may adversely affect our results of operations, consolidated financial position, or liquidity.

We face certain human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements.

Workforce demographic issues challenge employers nationwide and are of particular concern to the electric utility and natural gas pipeline industry. The median age of utility and natural gas pipeline workers is significantly higher than the national average. Over the next three years, approximately 30 percent of our current employees will be eligible to retire with full pension benefits. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business.

We are a holding company with our primary assets being investments in our subsidiaries.

We are a holding company and thus our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and our ability to pay our dividends and service our indebtedness depends upon the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends. At December 31, 2009, the Company and its subsidiaries had outstanding indebtedness and other liabilities of approximately $5.2 billion. Our subsidiaries are separate legal entities that have no obligation to pay any amounts due on our indebtedness or to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary's ability to pay dividends to us depends on any statutory and contractual restrictions that may be applicable to such subsidiary, which may include requirements to maintain minimum levels of working capital and other assets. Claims of creditors, including general creditors, of our subsidiaries on the assets of these subsidiaries will have priority over our claims generally (except to the extent that we may be a creditor of the subsidiaries and our claims are recognized) and claims by our shareowners.

In addition, as discussed above, OG&E is regulated by state utility commissions in Oklahoma and Arkansas which generally possess broad powers to ensure that the needs of the utility customers are being met. To the extent that the state commissions attempt to impose restrictions on the ability of OG&E to pay dividends to us, it could adversely affect our ability to continue to pay dividends.

Certain provisions in our charter documents and rights plan have anti-takeover effects.

Certain provisions of our certificate of incorporation and bylaws, as well as the Oklahoma corporations statute, may have the effect of delaying, deferring or preventing a change in control of the Company. Such provisions, including those regulating the nomination of directors, limiting who may call special stockholders' meetings and eliminating stockholder action by written consent, together with the possible issuance of preferred stock of the Company without stockholder approval, may make it more difficult for other persons, without the approval of our board of directors, to make a tender offer or otherwise acquire substantial amounts of our common stock or to launch other takeover attempts that a stockholder might consider to be in such stockholder's best interest. Additionally, our rights plan may also delay, defer or prevent a change of control of the Company. Under the rights plan, each outstanding share of common stock has one half of a right attached that trades with the common stock. Absent prior action by our board of directors to redeem the rights or amend the rights plan, upon the consummation of certain acquisition transactions, the rights would entitle the holder thereof (other than the acquiror) to purchase shares of common stock at a discounted price in a manner designed to result in substantial dilution to the acquiror. These provisions could limit the price that investors might be willing to pay in the future for shares of our common stock, discourage third party bidders from bidding for us and could significantly impede the ability of the holders of our common stock to change our management.

We and our subsidiaries may be able to incur substantially more indebtedness, which may increase the risks created by our indebtedness.

The terms of the indentures governing our debt securities do not fully prohibit us or our subsidiaries from incurring additional indebtedness. If we or our subsidiaries are in compliance with the financial covenants set forth in our revolving credit agreements and the indentures governing our debt securities, we and our subsidiaries may be able to incur substantial additional indebtedness. If we or any of our subsidiaries incur additional indebtedness, the related risks that we and they now face may intensify.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships or limit our ability to obtain financing on favorable terms.

We cannot assure that any of our current ratings or the ratings of our subsidiaries' will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Our ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruption as experienced with the market turmoil in late 2008 and early 2009. Pricing grids associated with our credit facilities could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrade 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 would also lead to higher long-term borrowing costs and, if below investment grade, would require us to post cash collateral or letters of credit.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

We have revolving credit agreements for working capital, capital expenditures, including acquisitions, and other corporate purposes. The levels of our debt could have important consequences, including the following:

- the ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or the financing may not be available on favorable terms;
- a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations and future business opportunities; and
- our debt levels may limit our flexibility in responding to changing business and economic conditions.

We are exposed to the credit risk of our key customers and counterparties, and any material nonpayment or nonperformance by our key customers and counterparties could adversely affect our consolidated financial position, results of operations and cash flows.

We are exposed to credit risks in our generation, retail distribution, pipeline and energy trading operations. Credit risk includes the risk that customers and counterparties that owe us money or energy will breach their obligations. If such parties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected, and we could incur losses.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

OG&E

OG&E owns and operates an interconnected electric generation, transmission and distribution system, located in Oklahoma and western Arkansas, which included 11 generating stations with an aggregate capability of approximately 6,641 MWs at December 31, 2009. The following tables set forth information with respect to OG&E's electric generating facilities, all of which are located in Oklahoma.

Station & Unit		Year Installed	Unit Design Type	Fuel Capability	Unit Run Type	2009 Capacity Factor (A)		Unit Capability (MW)	Station Capability (MW)
Muskogee	3	1956	Steam-Turbine	Gas	Base Load	---%	(B)	---	
	4	1977	Steam-Turbine	Coal	Base Load	51.3%		505	
	5	1978	Steam-Turbine	Coal	Base Load	69.4%		517	
	6	1984	Steam-Turbine	Coal	Base Load	63.8%		502	1,524
Seminole	1	1971	Steam-Turbine	Gas	Base Load	23.1%		491	
	1GT	1971	Combustion-Turbine	Gas	Peaking	0.1%	(C)	17	
	2	1973	Steam-Turbine	Gas	Base Load	22.7%		494	
	3	1975	Steam-Turbine	Gas/Oil	Base Load	18.3%		502	1,504
Sooner	1	1979	Steam-Turbine	Coal	Base Load	68.4%		522	
	2	1980	Steam-Turbine	Coal	Base Load	72.2%		524	1,046
Horseshoe	6	1958	Steam-Turbine	Gas/Oil	Base Load	15.8%		159	
Lake	7	1963	Combined Cycle	Gas/Oil	Base Load	19.2%		227	
	8	1969	Steam-Turbine	Gas	Base Load	4.6%		380	
	9	2000	Combustion-Turbine	Gas	Peaking	4.7%	(C)	46	
	10	2000	Combustion-Turbine	Gas	Peaking	4.3%	(C)	46	858
Mustang	1	1950	Steam-Turbine	Gas	Peaking	2.3%	(C)	50	
	2	1951	Steam-Turbine	Gas	Peaking	2.3%	(C)	51	
	3	1955	Steam-Turbine	Gas	Base Load	9.9%		113	
	4	1959	Steam-Turbine	Gas	Base Load	13.6%		253	
	5A	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	0.6%	(C)	32	
	5B	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	1.1%	(C)	32	531
Redbud (D)	1	2003	Combined Cycle	Gas	Base Load	35.3%		149	
	2	2003	Combined Cycle	Gas	Base Load	45.4%		147	
	3	2003	Combined Cycle	Gas	Base Load	43.9%		148	
	4	2003	Combined Cycle	Gas	Base Load	46.6%		145	589
McClain (E)	1	2001	Combined Cycle	Gas	Base Load	82.7%		346	346
Woodward	1	1963	Combustion-Turbine	Gas	Peaking	---%	(B) (C)	---	---
Enid	1	1965	Combustion-Turbine	Gas	Peaking	---%	(B) (C)	---	
	2	1965	Combustion-Turbine	Gas	Peaking	---%	(B) (C)	---	
	3	1965	Combustion-Turbine	Gas	Peaking	0.2%	(C)	11	
	4	1965	Combustion-Turbine	Gas	Peaking	0.1%	(C)	11	22
Total Generating Capability (all stations, excluding winds station)									6,420

Station	Year Installed	Location	Number of Units	Fuel Capability	2009 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Centennial	2007	Woodward, OK	80	Wind	34.2%	1.5	120
OU Spirit (F)	2009	Woodward, OK	44	Wind	---%	2.3	101
Total Generating Capability (wind stations)							221

(A) 2009 Capacity Factor = 2009 Net Actual Generation / (2009 Net Maximum Capacity (Nameplate Rating in MWs) x Period Hours (8,760 Hours)).
(B) This unit did not demonstrate summer capability in 2009 as prescribed by the SPP criteria.
(C) Peaking units are used when additional short-term capacity is required.
(D) The original units at the Redbud Facility were installed in 2003. In September 2008, OG&E purchased a 51 percent ownership interest in the Redbud Facility.
(E) Represents OG&E's 77 percent ownership interest in the McClain Plant.
(F) OU Spirit's 44 turbines were placed into service in November and December 2009.

At December 31, 2009, OG&E's transmission system included: (i) 48 substations with a total capacity of approximately 9.9 million kilo Volt-Amps ("kVA") and approximately 4,064 structure miles of lines in Oklahoma and (ii) seven substations with a total capacity of approximately 2.5 million kVA and approximately 271 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 348 substations with a total capacity of approximately 8.9 million kVA, 26,316 structure miles of overhead lines, 1,729 miles of underground conduit and 8,806 miles of underground conductors in Oklahoma and (ii) 38 substations with a total capacity of approximately 1.1 million kVA, 2,239 structure miles of overhead lines, 187 miles of underground conduit and 567 miles of underground conductors in Arkansas.

OG&E owns 140,133 square feet of office space at its executive offices at 321 North Harvey, Oklahoma City, Oklahoma 73101. In addition to its executive offices, OG&E owns numerous facilities throughout its service territory that support its operations. These facilities include, but are not limited to, district offices, fleet and equipment service facilities, operation support and other properties.

Enogex

Enogex's real property falls into two categories: (i) parcels that it owns in fee and (ii) parcels in which Enogex's interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for its operations. Certain of Enogex's processing plants and related facilities are located on land Enogex owns in fee title, and Enogex believes that it has satisfactory title to these lands. The remainder of the land on which Enogex's plants and related facilities are located is held by Enogex pursuant to ground leases between Enogex, as lessee, and the fee owner of the lands, as lessors. Enogex, or its predecessors, have leased these lands for many years without any material challenge known to us or Enogex relating to the title to the land upon which the assets are located, and Enogex believes that it has satisfactory leasehold estates to such lands. Enogex has no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by Enogex or to its title to any material lease, easement, right-of-way, permit or lease, and Enogex believes that it has satisfactory title to all of its material leases, easements, rights-of-way, permits and licenses.

Record title to some of Enogex's assets may reflect names of prior owners until Enogex has made the appropriate filings in the jurisdictions in which such assets are located. Title to some of Enogex's assets may be subject to encumbrances. We believe that none of such encumbrances should materially detract from the value of Enogex's properties or our interest in those properties or should materially interfere with Enogex's use of them in the operation of its business. Substantially all of Enogex's pipelines are constructed on rights-of-way granted by the apparent owners of record of the properties. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the rights-of-way grants.

At December 31, 2009, Enogex and its subsidiaries owned: (i) approximately 5,846 miles of intrastate natural gas gathering pipelines in Oklahoma and Texas, (ii) approximately 2,181 miles of intrastate natural gas transportation pipelines in Oklahoma and Texas, (iii) two underground natural gas storage facilities in Oklahoma operating at a working gas level of approximately 24 Bcf with approximately 650 MMcf/d of maximum withdrawal capacity and approximately 650 MMcf/d of injection capacity and (iv) eight operating natural gas processing plants, with a total inlet capacity of approximately 943 MMcf/d, a 50 percent interest in the Atoka natural gas processing plant with an inlet capacity of approximately 20 MMcf/d and two idle natural gas processing plants, all located in Oklahoma. The following table sets forth information with respect to Enogex's active natural gas processing plants:

Processing Plant	Year Installed	Type of Plant	Fuel Capability	2009 Average Daily Inlet Volumes (MMcf/d)	Inlet Capacity (MMcf/d)
Calumet (A)	1969	Lean Oil	Gas/Electric	129	250
Cox City (B)	1994	Cryogenic	Gas/Electric	162	180
Thomas (A)	1981	Cryogenic	Gas	131	135
Clinton (A)(C)	2009	Cryogenic	Electric	22	120
Roger Mills (B)	2008	Refrigeration	Electric	42	100
Canute (B)	1996	Cryogenic	Electric	55	60
Wetumka (A)	1983	Cryogenic	Gas/Electric	47	60
Harrah (A)	1994	Cryogenic	Gas/Electric	13	38
Atoka (D)	2007	Refrigeration	Electric	16	20
Total				617	963

(A) These processing plants are located on property that Enogex owns in fee.
(B) These processing plants are located on easements or leased property as described above.
(C) The Clinton plant was placed in service in late October 2009.
(D) This processing plant is leased and located on property that Atoka owns in fee.

Enogex occupies 116,184 square feet of office space at its executive offices at 515 Central Park Drive, Suite 110, Oklahoma City, Oklahoma 73105 under a lease that expires March 31, 2012. Although Enogex may require additional office space as its business expands, Enogex believes that its existing facilities are adequate to meet its needs for the immediate future. In addition to its executive offices, Enogex owns numerous facilities throughout its service territory that support its operations. These facilities include, but are not limited to, district offices, fleet and equipment service facilities, compressor station facilities, operation support and other properties.

During the three years ended December 31, 2009, the Company's gross property, plant and equipment (excluding construction work in progress) additions were approximately $2.5 billion and gross retirements were approximately $157.5 million. These additions were provided by cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper), long-term borrowings and permanent financings. The additions during this three-year period amounted to approximately 29.3 percent of gross property, plant and equipment (excluding construction work in progress) at December 31, 2009.

Item 3. Legal Proceedings.

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

1. *United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E.* (U.S. District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) *United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al.* (U.S. District Court for the Eastern District of Louisiana, Case No. 97-2089; U.S. District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with the plaintiff's complaint, which was a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the Federal government, alleged: (a) each of the named defendants had improperly or intentionally mismeasured gas (both volume and Btu content) purchased from Federal and Indian lands which resulted in the under reporting and underpayment of gas royalties owed to the Federal government; (b) certain provisions generally found in gas purchase contracts were improper; (c) transactions by affiliated companies were not arms-length; (d) excess processing cost deduction; and (e) failure to account for production separated out as a result of gas processing. Grynberg sought the following damages: (a) additional royalties which he claimed 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. Various appeals and hearings were held in this matter from 2006 to late 2009. In October 2009, this matter concluded with the dismissal of all complaints against all Company parties. The Company now considers this case closed and, as a result, during the third quarter of 2009, the Company reversed a reserve of approximately $1.5 million that was originally established with the 1999 acquisition of Transok.

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

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

The class certification issues were briefed and argued by the parties in 2005 and proposed findings of facts and conclusions of law on class certification were filed in 2007. On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On February 10, 2010 the court heard arguments on the rehearing. No ruling on this motion has been made.

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

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

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

The class certification issues were briefed and argued by the parties in 2005 and proposed findings of facts and conclusions of law on class certification were filed in 2007. On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On February 10, 2010 the court heard arguments on the rehearing. No ruling on this motion has been made.

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

4. *Oklahoma Royalty Lawsuit.* On July 22, 2005, Enogex along with certain other unaffiliated co-defendants was served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including Enogex and its subsidiaries, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs' wells. The plaintiffs assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages in excess of $10,000, plus attorneys' fees and costs, and punitive damages in excess of $10,000. Enogex and its subsidiaries filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs' right to conduct discovery and the possible re-filing of their allegations in the petition against the Enogex companies. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Company (collectively, "BP"), filed a cross claim against Products seeking indemnification and/or contribution from Products based upon the 1997 sale of a third-party interest in one of Products natural gas processing plants. On May 17, 2006, the plaintiffs filed an amended petition against Enogex and its subsidiaries. Enogex and its subsidiaries filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion was held on November 20, 2006 and the court denied Enogex's motion. Enogex companies filed an answer to the amended petition and BP's cross claim on January 16, 2007. Based on Enogex's investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to continue vigorously defending this case.

5. *Hull v. Enogex LLC.* On November 14, 2008, a natural gas gathering pipeline owned by Enogex ruptured in Grady County, near Alex, Oklahoma, resulting in a fire that caused injuries to one resident and destroyed three residential structures. The cause of the rupture is not known and an investigation of the incident is ongoing. The damaged pipeline hasbeen repaired and the pipeline is back in service. After the incident, Enogex coordinated and assisted the affected residents. Enogex resolved matters with two of the residents and Enogex continues to seek resolution with a remaining resident. This resident filed a legal action in May 2009 in the District Court of Cleveland County, Oklahoma, against OGE Energy and Enogex seeking to recover actual and punitive damages in excess of $10,000. The parties participated in a mediation of the

pending action in August but were unable to resolve the action. Enogex has requested information regarding property and non-economic damage from the plaintiffs but has not yet received a response. Enogex intends to make full payment for actual medical expenses and property damages in this case. While the Company cannot predict the outcome of this lawsuit at this time, the Company intends to vigorously defend any demand for punitive damages or excessive compensatory damages in this case and believes that its ultimate resolution will not be material to the Company's consolidated financial position or results of operations.

6. *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 authorizes OG&E to collect the challenged franchise fee charges. On March 10, 2009, the Oklahoma Attorney General, OG&E, OG&E Shareholders Association and the Staff of the Public Utility Division of the OCC all filed briefs arguing that the application should be dismissed. On December 9, 2009 the OCC issued an order dismissing the plaintiffs' request for a modification of the OCC order which authorizes OG&E to collect and remit sales tax on franchise fee charges. In its December 9, 2009 order, the OCC advised the plaintiffs that the ruling does not address the question of whether OG&E's collection and remittance of such sales tax should be discontinued prospectively. On December 21, 2009, the plaintiffs filed a motion at the Oklahoma Supreme Court asking the court to deny OG&E's writ of prohibition and to remand the cause to the District Court. On December 29, 2009, the Oklahoma Supreme Court declared the plaintiffs' motion moot. On January 27, 2010, the OCC Staff filed a motion asking the OCC to dismiss the cause and close the cause at the OCC. If the OCC Staff's motion is granted, the plaintiffs would be required to file a new cause in order to ask for prospective relief. In its motion, the OCC Staff stated that the plaintiff's counsel advised the OCC Staff counsel that the plaintiffs have no desire to seek a determination regarding prospective relief from the OCC. It is unknown whether the plaintiffs will attempt to continue the District Court action. OG&E believes that the lawsuit is without merit.

7. *Oxley Litigation.* OG&E has been sued by John C. Oxley D/B/A Oxley Petroleum et al. in the District Court of Haskell County, Oklahoma. This case has been pending for more than 11 years. The plaintiffs alleged that OG&E breached the terms of contracts covering several wells by failing to purchase gas from the plaintiffs in amounts set forth in the contracts. The plaintiffs' most recent Statement of Claim describes approximately $2.7 million in take-or-pay damages (including interest) and approximately $36 million in contract repudiation damages (including interest), subject to the limitation described below. In 2001, OG&E agreed to provide the plaintiffs with approximately $5.8 million of consideration and the parties agreed to arbitrate the dispute. Consequently, OG&E will only be liable for the amount, if any, of an arbitration award in excess of $5.8 million. The arbitration hearing was completed recently and the next step is briefing by the parties. While the Company cannot predict the precise outcome of the arbitration, based on the information known at this time, OG&E believes that this lawsuit will not have a material adverse effect on the Company's consolidated financial position or results of operations.

Item 4. Submission of Matters to a Vote of Security Holders.

None.

Executive Officers of the Registrant.

The following persons were Executive Officers of the Registrant as of February 18, 2010:

Name	Age	Title
Peter B. Delaney	56	Chairman of the Board, President and Chief Executive Officer - OGE Energy Corp. and Chief Executive Officer - Enogex LLC
Danny P. Harris	54	Senior Vice President and Chief Operating Officer - OGE Energy Corp. and President - Enogex LLC
Sean Trauschke	42	Vice President and Chief Financial Officer - OGE Energy Corp. and Chief Financial Officer - Enogex LLC
Patricia D. Horn	51	Vice President - Governance and Environmental, Health & Safety; Corporate Secretary - OGE Energy Corp.
Gary D. Huneryager	59	Vice President - Internal Audits - OGE Energy Corp.
S. Craig Johnston	49	Vice President - Strategic Planning and Marketing - OGE Energy Corp.
Jesse B. Langston	47	Vice President - Utility Commercial Operations - OG&E
Jean C. Leger, Jr.	51	Vice President - Utility Operations - OG&E
Cristina F. McQuistion	45	Vice President - Process and Performance Improvement - OGE Energy Corp.
Stephen E. Merrill	45	Vice President - Human Resources - OGE Energy Corp.
E. Keith Mitchell	47	Senior Vice President and Chief Operating Officer - Enogex LLC
Howard W. Motley	61	Vice President - Regulatory Affairs - OG&E
Reid V. Nuttall	52	Vice President - Chief Information Officer - OGE Energy Corp.
Melvin H. Perkins, Jr.	61	Vice President - Power Delivery - OG&E
Paul L. Renfrow	53	Vice President - Public Affairs - OGE Energy Corp.
John Wendling, Jr.	53	Vice President - Power Supply - OG&E
Max J. Myers	35	Treasurer - OGE Energy Corp.
Scott Forbes	52	Controller and Chief Accounting Officer - OGE Energy Corp.
Jerry A. Peace	47	Chief Risk Officer - OGE Energy Corp.

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Delaney, Harris, Trauschke, Huneryager, Johnston, Merrill, Nuttall, Renfrow, Myers, Forbes and Peace and Ms. Horn and Ms. McQuistion are also officers of OG&E. Each officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Shareowners, currently scheduled for May 20, 2010.

The business experience of each of the Executive Officers of the Registrant for the past five years is as follows:

Name	Business Experience	
Peter B. Delaney	2007 – Present:	Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp. and OG&E
	2005 – Present:	Chief Executive Officer of Enogex LLC
	2007:	President and Chief Operating Officer of OGE Energy Corp. and OG&E
	2005 – 2007:	Executive Vice President and Chief Operating Officer of OGE Energy Corp. and OG&E
	2005:	President of Enogex Inc.
Danny P. Harris	2007 – Present:	Senior Vice President and Chief Operating Officer of OGE Energy Corp. and OG&E and President of Enogex LLC
	2005 – 2007:	Senior Vice President of OGE Energy Corp. and President and Chief Operating Officer of Enogex Inc.
	2005:	Vice President and Chief Operating Officer of Enogex Inc.
Sean Trauschke	2009 – Present:	Vice President and Chief Financial Officer of OGE Energy Corp. and OG&E and Chief Financial Officer of Enogex LLC
	2007 – 2009:	Senior Vice President – Investor Relations and Financial Planning of Duke Energy
	2006 – 2007:	Vice President – Investor Relations of Duke Energy
	2005 – 2006:	Vice President and Chief Risk Officer of Duke Energy (electric utility)
Patricia D. Horn	2010 – Present:	Vice President – Governance and Environmental, Health & Safety; Corporate Secretary of OGE Energy Corp. and OG&E
	2005 – 2010:	Vice President – Legal, Regulatory and Environmental Health & Safety, General Counsel and Secretary of Enogex LLC
	2005 – 2010:	Assistant General Counsel of OGE Energy Corp.
Gary D. Huneryager	2005 – Present:	Vice President – Internal Audits of OGE Energy Corp. and OG&E
	2005:	Internal Audit Officer of OGE Energy Corp. and OG&E
S. Craig Johnston	2007 – Present:	Vice President – Strategic Planning and Marketing of OGE Energy Corp. and OG&E
	2005 – 2007:	Senior Vice President of Worldwide Oil & Gas Markets of Air Liquide (industrial gases company)
Jesse B. Langston	2006 – Present:	Vice President – Utility Commercial Operations of OG&E
	2005 – 2006:	Director – Utility Commercial Operations of OG&E
	2005:	Director – Corporate Planning of OG&E
Jean C. Leger, Jr.	2008 – Present:	Vice President – Utility Operations of OG&E
	2005 – 2008:	Vice President of Operations of Enogex LLC
	2005:	Director of Field Operations of Enogex Inc.
Cristina F. McQuistion	2008 – Present:	Vice President – Process and Performance Improvement of OGE Energy Corp. and OG&E
	2007 – 2008:	Executive Vice President and General Manager Point of Sale Systems of Teleflora
	2005 – 2007:	Executive Vice President – Member Services of Teleflora (floral industry and software services to floral industry company)
Stephen E. Merrill	2009 – Present:	Vice President – Human Resources of OGE Energy Corp. and OG&E
	2007 – 2009:	Vice President and Chief Financial Officer of Enogex LLC
	2006 – 2007:	Vice President and Chief Financial Officer of Cayenne Drilling, LLC and Sunstone Energy Group LLC (oil and gas company)
	2005 – 2006:	Director of U.S. Operations at Plains All-American Pipeline L.P. (natural gas pipeline company)

Name		Business Experience
E. Keith Mitchell	2007 – Present:	Senior Vice President and Chief Operating Officer of Enogex LLC
	2007:	Senior Vice President of Enogex Inc.
	2005 – 2007:	Vice President – Transportation Services of Enogex Inc.
Howard W. Motley	2006 – Present:	Vice President – Regulatory Affairs of OG&E
	2005 – 2006:	Director – Regulatory Affairs and Strategy of OG&E
Reid V. Nuttall	2009 – Present:	Vice President – Chief Information Officer of OGE Energy Corp. and OG&E
	2006 – 2009:	Vice President – Enterprise Information and Performance of OGE Energy Corp. and OG&E
	2005 – 2006:	Vice President – Enterprise Architecture of National Oilwell Varco (oil and gas equipment company)
	2005:	Chief Information Officer, Vice President – Information Technology of Varco International (oil and gas equipment company)
Melvin H. Perkins, Jr.	2007 – Present:	Vice President – Power Delivery of OG&E
	2005 – 2007:	Vice President – Transmission of OG&E
Paul L. Renfrow	2005 – Present:	Vice President – Public Affairs of OGE Energy Corp. and OG&E
	2005:	Director – Public Affairs of OGE Energy Corp. and OG&E
John Wendling, Jr.	2007 – Present:	Vice President – Power Supply of OG&E
	2005 – 2007:	Director – Power Plant Operations of OG&E
	2005:	Plant Manager – Sooner Power Plant of OG&E
Max J. Myers	2009 – Present:	Treasurer of OGE Energy Corp. and OG&E
	2008:	Managing Director of Corporate Development and Finance of OGE Energy Corp. and OG&E
	2005 – 2008:	Manager of Corporate Development of OGE Energy Corp. and OG&E
	2005:	Director of Corporate Finance and Development of Westar Energy, Inc. (electric utility)
Scott Forbes	2005 – Present:	Controller and Chief Accounting Officer of OGE Energy Corp. and OG&E
	2008 – 2009:	Interim Chief Financial Officer of OGE Energy Corp. and OG&E
	2005:	Chief Financial Officer of First Choice Power (retail electric provider)
	2005:	Senior Vice President and Chief Financial Officer of Texas New Mexico Power Company (electric utility)
Jerry A. Peace	2008 – Present:	Chief Risk Officer of OGE Energy Corp. and OG&E
	2005 – 2008:	Chief Risk Officer and Compliance Officer of OGE Energy Corp. and OG&E

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

The Company's Common Stock is listed for trading on the New York Stock Exchange under the ticker symbol "OGE." Quotes may be obtained in daily newspapers where the common stock is listed as "OGE Engy" in the New York Stock Exchange listing table. The following table gives information with respect to price ranges, as reported in *The Wall Street Journal* as New York Stock Exchange Composite Transactions, and dividends paid for the periods shown.

	Dividend	Price	
2010	Paid	High	Low
First Quarter (through January 31)	$ 0.3625	$ 37.92	$ 35.50

	Dividend	Price	
2009	Paid	High	Low
First Quarter	$ 0.3550	$ 26.80	$ 19.70
Second Quarter	0.3550	28.55	23.19
Third Quarter	0.3550	33.72	26.50
Fourth Quarter	0.3550	37.79	31.66

	Dividend	Price	
2008	Paid	High	Low
First Quarter	$ 0.3475	$ 36.23	$ 29.83
Second Quarter	0.3475	34.02	30.61
Third Quarter	0.3475	34.74	29.67
Fourth Quarter	0.3475	31.41	19.56

The number of record holders of the Company's Common Stock at December 31, 2009, was 21,971. The book value of the Company's Common Stock at December 31, 2009, was $21.06.

Dividend Restrictions

Before the Company can pay any dividends on its common stock, the holders of any of its preferred stock that may be outstanding are entitled to receive their dividends at the respective rates as may be provided for the shares of their series. Currently, there are no shares of preferred stock of the Company outstanding. Because the Company is a holding company and conducts all of its operations through its subsidiaries, the Company's cash flow and ability to pay dividends will be dependent on the earnings and cash flows of its subsidiaries and the distribution or other payment of those earnings to the Company in the form of dividends or distributions, or in the form of repayments of loans or advances to it. The Company expects to derive principally all of the funds required by it to enable it to pay dividends on its common stock from dividends paid by OG&E, on OG&E's common stock, and from distributions paid by Enogex, on Enogex's limited liability company interests. The Company's ability to receive dividends on OG&E's common stock is subject to the prior rights of the holders of any OG&E preferred stock that may be outstanding and the covenants of OG&E's certificate of incorporation and its debt instruments limiting the ability of OG&E to pay dividends. The Company's ability to receive distributions on Enogex's limited liability company interests is subject to the prior rights of existing and future holders of such limited liability company interests that may be outstanding and the covenants of Enogex's debt instruments (including its revolving credit agreement) limiting the ability of Enogex to pay distributions.

Under OG&E's certificate of incorporation, if any shares of its preferred stock are outstanding, dividends (other than dividends payable in common stock), distributions or acquisitions of OG&E common stock:

- may not exceed 50 percent of OG&E's net income for a prior 12-month period, after deducting dividends on any preferred stock during the period, if the sum of the capital represented by the common stock, premiums on capital stock (restricted to premiums on common stock only by Securities and Exchange Commission orders), and surplus accounts is less than 20 percent of capitalization;

- may not exceed 75 percent of OG&E's net income for such 12-month period, as adjusted if this capitalization ratio is 20 percent or more, but less than 25 percent; and

- if this capitalization ratio exceeds 25 percent, dividends, distributions or acquisitions may not reduce the ratio to less than 25 percent except to the extent permitted by the provisions described in the above two bullet points.

OG&E's certificate of incorporation further provides that no dividend may be declared or paid on the OG&E common stock until all amounts required to be paid or set aside for any sinking fund for the redemption or purchase of OG&E cumulative preferred stock, par value $25 per share, have been paid or set aside. Currently, no shares of OG&E preferred stock are outstanding and no portion of the retained earnings of OG&E is presently restricted by these provisions.

Under Enogex's current revolving credit agreement, Enogex generally may not make distributions if an event of default exists and otherwise may make monthly and quarterly distributions in amounts not to exceed the amount by which Enogex's cash on hand exceeds its current and anticipated needs, including, without limitation, for operating expenses, debt service, acquisitions and a reasonable contingency reserve.

Issuer Purchases of Equity Securities

The shares indicated below represent shares of Company common stock purchased on the open market by the trustee for the Company's 401(k) Plan and reflect shares purchased with employee contributions as well as the portion attributable to the Company's matching contributions.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
1/1/09 – 1/31/09	81,300	$ 25.33	N/A	N/A
2/1/09 – 2/28/09	145,200	$ 23.55	N/A	N/A
3/1/09 – 3/31/09	75,900	$ 22.93	N/A	N/A
4/1/09 – 4/30/09	121,500	$ 24.13	N/A	N/A
5/1/09 – 5/31/09	53,800	$ 26.18	N/A	N/A
6/1/09 – 6/30/09	86,800	$ 26.85	N/A	N/A
7/1/09 – 7/31/09	142,600	$ 28.70	N/A	N/A
8/1/09 – 8/31/09	61,700	$ 31.39	N/A	N/A
9/1/09 – 9/30/09	17,800	$ 31.39	N/A	N/A
10/1/09 – 10/31/09	130,200	$ 33.88	N/A	N/A
11/1/09 – 11/30/09	55,900	$ 33.42	N/A	N/A
12/1/09 – 12/31/09	53,000	$ 36.14	N/A	N/A

N/A – not applicable

Item 6. Selected Financial Data.

HISTORICAL DATA

Year ended December 31	**2009 (A)**	2008	2007	2006	2005
SELECTED FINANCIAL DATA					
(In millions, except per share data)					
Results of Operations Data:					
Operating revenues	**$ 2,869.7**	$ 4,070.7	$ 3,797.6	$ 4,005.6	$ 5,911.5
Cost of goods sold	**1,557.7**	2,818.0	2,634.7	2,902.5	4,942.3
Gross margin on revenues	**1,312.0**	1,252.7	1,162.9	1,103.1	969.2
Other operating expenses	**820.1**	790.6	707.6	670.4	646.8
Operating income	**491.9**	462.1	455.3	432.7	322.4
Interest income	**1.4**	6.7	2.1	6.2	3.5
Allowance for equity funds used during construction	**15.1**	---	---	4.1	---
Other income (loss)	**27.5**	15.4	17.4	16.3	(0.3)
Other expense	**16.3**	25.6	22.7	16.7	5.5
Interest expense	**137.4**	120.0	90.2	96.0	90.3
Income tax expense	**121.1**	101.2	116.7	120.5	68.6
Income from continuing operations	**261.1**	237.4	245.2	226.1	161.2
Income from discontinued operations, net of tax	**---**	---	---	36.0	49.8
Net income	**261.1**	237.4	245.2	262.1	211.0
Less: Net income attributable to noncontrolling interest	**2.8**	6.0	1.0	---	---
Net income attributable to OGE Energy	**$ 258.3**	$ 231.4	$ 244.2	$ 262.1	$ 211.0
Basic earnings per average common share attributable to OGE Energy common shareholders					
Income from continuing operations	**$ 2.68**	$ 2.50	$ 2.66	$ 2.48	$ 1.79
Income from discontinued operations, net of tax	**---**	---	---	0.40	0.55
Net income attributable to OGE Energy common shareholders	**$ 2.68**	$ 2.50	$ 2.66	$ 2.88	$ 2.34
Diluted earnings per average common share attributable to OGE Energy common shareholders					
Income from continuing operations	**$ 2.66**	$ 2.49	$ 2.64	$ 2.45	$ 1.77
Income from discontinued operations, net of tax	**---**	---	---	0.39	0.55
Net income attributable to OGE Energy common shareholders	**$ 2.66**	$ 2.49	$ 2.64	$ 2.84	$ 2.32
Dividends declared per share	**$ 1.4275**	$ 1.3975	$ 1.3675	$ 1.3375	$ 1.33
Balance Sheet Data (at period end):					
Property, plant and equipment, net	**$ 5,911.6**	$ 5,249.8	$ 4,246.3	$ 3,867.5	$ 3,567.4
Total assets	**$ 7,266.7**	$ 6,518.5	$ 5,237.8	$ 4,898.4	$ 4,871.4
Long-term debt	**$ 2,088.9**	$ 2,161.8	$ 1,344.6	$ 1,346.3	$ 1,350.8
Total stockholders' equity	**$ 2,060.8**	$ 1,914.0	$ 1,691.6	$ 1,603.8	$ 1,375.7
CAPITALIZATION RATIOS (B)					
Stockholders' equity	**46.4%**	47.0%	55.7%	54.3%	50.5%
Long-term debt	**53.6%**	53.0%	44.3%	45.7%	49.5%
RATIO OF EARNINGS TO FIXED CHARGES (C)					
Ratio of earnings to fixed charges	**3.38**	3.50	4.65	4.28	3.37

(A) Effective January 1, 2009, the Company changed the presentation of the Atoka noncontrolling interest in the Company's consolidated financial statements related to the adoption of a new accounting principle and restated prior periods for consistency.
(B) Capitalization ratios = [Total stockholders' equity / (Total stockholders' equity + Long-term debt + Long-term debt due within one year)] and [(Long-term debt + Long-term debt due within one year) / (Total stockholders' equity + Long-term debt + Long-term debt due within one year)].
(C) For purposes of computing the ratio of earnings to fixed charges, (i) earnings consist of pre-tax income from continuing operations plus fixed charges, less allowance for borrowed funds used during construction and other capitalized interest and (ii) fixed charges consist of interest on long-term debt, related amortization, interest on short-term borrowings and a calculated portion of rents considered to be interest.

Item 7. 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 rate 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 gas business in 1928 and is no longer engaged in the gas distribution business.

Enogex LLC and its subsidiaries ("Enogex") are providers of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. Prior to January 1, 2008, Enogex owned OGE Energy Resources, Inc. ("OERI"), whose primary operations are in natural gas marketing. On January 1, 2008, Enogex distributed the stock of OERI to OGE Energy. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream, LLC joint venture ("Atoka") through Enogex Atoka LLC, a wholly-owned subsidiary of Enogex Gathering & Processing LLC.

Executive Overview

Strategy

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

OG&E has been focused on increased investment to preserve system reliability and meet load growth, leverage unique geographic position to develop renewable energy resources for wind and transmission, replace infrastructure equipment, replace aging transmission and distribution systems, provide new products and services, provide energy management solutions to OG&E's customers through the Smart Grid program (discussed below) and deploy newer technology that improves operational, financial and environmental performance. As part of this plan, OG&E has taken, or has committed to take, the following actions:

- in January 2007, a 120 megawatt ("MW") wind farm in northwestern Oklahoma was placed in service;
- in September 2008, OG&E purchased a 51 percent interest in the 1,230 MW natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma ("Redbud Facility");
- in 2008, OG&E announced a "Positive Energy Smart Grid" initiative that will empower customers to proactively manage their energy consumption during periods of peak demand. As a result of the American Recovery and Reinvestment Act of 2009 ("ARRA") signed by the President into law in February 2009, OG&E requested a $130 million grant from the U.S. Department of Energy ("DOE") in August 2009 to develop its Smart Grid technology. In late October 2009, OG&E received notification from the DOE that its grant had been accepted by the DOE;
- in 2008, OG&E began construction of a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma ("Windspeed"), which is a critical first step to increased wind development in western Oklahoma. This transmission line is expected to be in service by April 2010;
- in June 2009, OG&E received Southwest Power Pool ("SPP") approval to build four 345 kilovolt ("kV") transmission lines referred to as "Balanced Portfolio 3E", which OG&E expects to begin constructing in early 2010. These transmission lines are expected to be in service between December 2012 and December 2014;
- in September 2009, OG&E signed power purchase agreements with two developers who are to build two new wind farms, totaling 280 MWs, in northwestern Oklahoma which OG&E intends to add to its power-generation portfolio by the end of 2010. OG&E will continue to evaluate renewable opportunities to add to its power-generation portfolio in the future;
- in November and December 2009, the individual turbines were placed in service related to the OU Spirit wind project in western Oklahoma ("OU Spirit"), which added 101 MWs of wind capacity to OG&E's wind portfolio; and
- OG&E's construction initiative from 2010 to 2015 includes approximately $2.6 billion in major projects designed to expand capacity, enhance reliability and improve environmental performance. This construction initiative also includes strengthening and expanding the electric transmission, distribution and substation systems and replacing aging infrastructure.

OG&E continues to pursue additional renewable energy and the construction of associated transmission facilities required to support this renewable expansion. OG&E also is promoting Demand Side Management programs to encourage more efficient use of electricity. See Note 14 of Notes to Consolidated Financial Statements (OG&E Conservation and Energy Efficiency Programs) for a further discussion. If these initiatives are successful, OG&E believes it may be able to defer the construction of any incremental fossil fuel generation capacity until 2020.

Increases in generation and the building of transmission lines are subject to numerous regulatory and other approvals, including appropriate regulatory treatment from the OCC and, in the case of transmission lines, the SPP. Other projects involve installing new emission-control and monitoring equipment at existing OG&E power plants to help meet OG&E's commitment to comply with current and future environmental requirements. For additional information regarding the above items and other regulatory matters, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations" and Note 14 of Notes to Consolidated Financial Statements.

Enogex's results of operations from the transportation and storage business are determined primarily by the volumes of natural gas transported on Enogex's intrastate pipeline system, volumes of natural gas stored at Enogex's storage facilities and the level of fees charged to Enogex's customers for such services. Enogex generates a majority of its revenues and margins for its pipeline business under fee-based transportation contracts that are directly related to the volume of natural gas capacity reserved on its system. The margin Enogex earns from its transportation activities is not directly dependent on commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, Enogex's revenues from these arrangements would be reduced. Results of operations from the gathering and processing business are determined primarily by the volumes of natural gas Enogex gathers and processes, its current contract portfolio and natural gas and natural gas liquids ("NGLs") prices. Because of the natural decline in production from existing wells connected to Enogex's systems, Enogex's success depends on its ability to gather new sources of natural gas, which depends on certain factors beyond its or our control. Any decrease in supplies of natural gas could adversely affect Enogex's gathering and processing business. As a result, Enogex's cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on its gathering systems and the asset utilization rates at its natural gas processing plants, Enogex must continually obtain new natural gas supplies. The primary factors affecting Enogex's ability to obtain new supplies of natural gas and attract new customers to its assets depends in part on the level of successful drilling activity near these systems, Enogex's ability to compete for volumes from successful new wells and Enogex's ability to expand capacity as needed.

Enogex plans to continue to implement improvements to enhance long-term financial performance of its mid-continent assets through more efficient operations and effective commercial management of the assets, capturing growth opportunities through expansion projects, increased utilization of existing assets and strategic acquisitions. Enogex also plans to continue to add additional fee-based business to its portfolio as opportunities become available. In addition, Enogex is seeking to diversify its gathering, processing and transportation businesses principally by expanding into other geographic areas that are complementary with the Company's strategic capabilities. Enogex expects to accomplish this diversification either by undertaking organic growth projects or through strategic acquisitions. Over the past several years, Enogex has been able to take advantage of numerous organic growth projects within its existing footprint including:

- expansions on the east side of Enogex's gathering system, primarily in the Woodford Shale play in southeastern Oklahoma through construction of new facilities and expansion of existing facilities and its interest in Atoka; and
- expansions on the west side of Enogex's gathering system, primarily in the Granite Wash play, Woodford Shale play and Atoka play in western Oklahoma and the Granite Wash play and Atoka play in the Wheeler County, Texas area, which is located in the Texas Panhandle.

In addition to focusing on growing its earnings and improving cash flow, Enogex intends to continue to prudently manage its business and execute on organic growth initiatives. The Company's business strategy is to continue maintaining the diversified asset position of OG&E and Enogex so as to provide competitive energy products and services to customers primarily in the south central United States. The Company will continue to focus on those products and services with limited or manageable commodity price exposure. Also, the Company believes that many of the risk management practices, commercial skills and market information available from OERI provide value to all of the Company's businesses.

Summary of Operating Results

2009 compared to 2008. Net income attributable to OGE Energy was approximately $258.3 million, or $2.66 per diluted share, in 2009 as compared to approximately $231.4 million, or $2.49 per diluted share, in 2008. The increase in net income attributable to OGE Energy of approximately $26.9 million, or $0.17 per diluted share, in 2009 as compared to 2008 was primarily due to:

- net income at OG&E of approximately $200.4 million in 2009 as compared to approximately $143.0 million in 2008, which was an increase in net income of approximately $57.4 million, or $0.52 per diluted share of the Company's common stock, in 2009 as compared to 2008 primarily due to a higher gross margin on revenues ("gross margin"), primarily due to rate increases and riders partially offset by milder weather and lower demand and related revenues by non-residential customers, and a higher allowance for equity funds used during construction ("AEFUDC") partially offset by higher depreciation and amortization expense, higher interest expense and higher income tax expense;
- net income at Enogex of approximately $66.3 million in 2009 as compared to approximately $91.2 million in 2008, which was a decrease in net income of approximately $24.9 million, or $0.30 per diluted share of the Company's common stock, in 2009 as compared 2008 primarily due to a lower gross margin, primarily due to lower processing spreads, lower NGLs prices and lower natural gas prices, and higher depreciation and amortization expense partially offset by lower operation and maintenance expense and lower income tax expense;
- net loss at OGE Energy of approximately $3.3 million in 2009 as compared to approximately $7.2 million in 2008, which was an improvement of approximately $3.9 million, or $0.05 per diluted share of the Company's common stock, in 2009 as compared to 2008 primarily due to lower operation and maintenance expense resulting from lower transaction costs associated with terminated transactions of approximately $8.8 million and a lower income tax benefit partially offset by lower other income due to receiving life insurance proceeds in 2008 from the death of one of the Company's directors in 2008 and higher depreciation and amortization expense; and
- net loss at OERI of approximately $5.1 million in 2009 as compared to net income of approximately $4.4 million in 2008, which was a decrease in net income of approximately $9.5 million, or $0.10 per diluted share of the Company's common stock, in 2009 as compared to 2008 primarily due to a lower gross margin

partially offset by lower operation and maintenance expense and an income tax benefit in 2009 as compared to income tax expense in 2008.

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

2008 compared to 2007. Net income attributable to OGE Energy was approximately $231.4 million, or $2.49 per diluted share, in 2008 as compared to approximately $244.2 million, or $2.64 per diluted share, in 2007. The decrease in net income attributable to OGE Energy of approximately $12.8 million, or $0.15 per diluted share, in 2008 as compared to 2007 was primarily due to:

- net income at OG&E of approximately $143.0 million in 2008 as compared to approximately $161.7 million in 2007, which was a decrease in net income of approximately $18.7 million, or $0.21 per diluted share of the Company's common stock, in 2008 as compared to 2007 primarily due to higher operation and maintenance expense, higher depreciation and amortization expense, higher other expense and higher interest expense partially offset by a higher gross margin due to increased rates from various regulatory riders implemented in 2008 and lower income tax expense;
- net income at Enogex of approximately $91.2 million in 2008 as compared to approximately $86.2 million in 2007, which was an increase in net income of approximately $5.0 million, or $0.05 per diluted share of the Company's common stock, in 2008 as compared to 2007 primarily due to a higher gross margin partially offset by higher operation and maintenance expense, higher depreciation and amortization expense, lower interest income, higher other expense and higher income tax expense. Net income for Enogex in 2007 included net income of approximately $10.9 million, or $0.12 per diluted share, attributable to OERI;
- net income at OERI of approximately $4.4 million, or $0.05 per diluted share of the Company's common stock, in 2008; and
- net loss at OGE Energy of approximately $7.2 million in 2008 as compared to approximately $3.7 million in 2007, which was an increase in the net loss of approximately $3.5 million, or $0.03 per diluted share of the Company's common stock, in 2008 as compared to 2007 primarily due to higher operation and maintenance expense related to the 2008 write-off of transaction costs incurred related to the proposed joint venture between OGE Energy and Energy Transfer Partners, L.P. that was terminated and transaction costs associated with the formation of OGE Enogex Partners, L.P. of approximately $8.8 million, partially offset by lower interest expense due to lower advances from subsidiaries, higher other income due to receiving life insurance proceeds in 2008 from the death of one of the Company's directors in 2008 and a higher income tax benefit due to a higher net loss.

Timing Items. Enogex's net income for 2007 was approximately $86.2 million, which included a loss of approximately $2.2 million resulting from recording OERI's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory were realized during the first and second quarters of 2008.

Recent Developments and Regulatory Matters

Changes in the Capital and Commodity Markets

The volatility in global capital markets experienced in late 2008 and early 2009 led to a reduction in the value of long-term investments held in OGE Energy's pension trust and postretirement benefit plan trusts. However, since the end of the first quarter of 2009, the market values have partially recovered from the decline in value experienced in late 2008 and early 2009.

Enogex's gathering and processing margins generally improve when NGLs 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 2009, commodity spreads increased over year-end 2008 levels but still remain lower than commodity spreads in early to mid-2008. As a result of the lower commodity spread environment, Enogex's results for 2009 were affected. Also, prices of natural gas and NGLs have been extremely volatile, and Enogex expects this volatility to continue.

Global Climate Change and Environmental Concerns

There is a growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation at the Federal level, actions at the state level, as well as litigation relating to greenhouse gas emissions. In June 2009, the U.S. House of Representatives passed legislation that would regulate greenhouse gas emissions by instituting a cap-and-trade-system, in which a cap on U.S. greenhouse gas emissions would be established starting in 2012 at a level three percent below the baseline 2005 level. The cap would decline over time until in 2050 it reaches 83 percent below the baseline level. Emission allowances, which are rights to emit greenhouse gases, would be both allocated for free and auctioned. In addition, the legislation contains a renewable energy standard of 25 percent by the year 2025 and an energy efficiency mandate for electric and natural gas utilities, as well as other requirements. Legislation pending in the U.S. Senate proposes to regulate greenhouse gas emissions by instituting a cap-and-trade-system, with primarily the same target levels proposed by the House bill; however, the proposed Senate bill is more aggressive in its 2020 target – a reduction to 20 percent below 2005 levels by 2020 (versus 17 percent in the House bill). It is uncertain at this time whether, and in what form, such legislation will ultimately be adopted. If legislation or regulations are passed at the Federal or state levels in the future requiring mandatory reductions of carbon dioxide and other greenhouse gases on generation facilities to address climate change, this could result in significant additional capital expenditures and compliance costs.

Uncertainty surrounding global climate change and environmental concerns related to new coal-fired generation development is changing the mix of the potential sources of new generation in the region. Adoption of renewable portfolio standards would be expected to increase the region's reliance on wind generation. The Company believes it can leverage its unique geographic position to develop renewable energy resources for wind and transmission to deliver the renewable energy.

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. On July 24, 2009, the OCC issued an order authorizing: (i) an annual net increase of approximately $48.3 million in OG&E's rates to its Oklahoma retail customers, which includes an increase in the residential customer charge from $6.50/month to $13.00/month, (ii) creation of a new recovery rider to permit the recovery of up to $20 million of capital expenditures and operation and maintenance expenses associated with OG&E's smart grid project in Norman, Oklahoma, which was implemented in February 2010, (iii) continued utilization of a return on equity of 10.75 percent under various recovery riders previously approved by the OCC and (iv) recovery through OG&E's fuel adjustment clause of approximately $4.8 million annually of certain expenses that historically had been recovered through base rates. New electric rates were implemented August 3, 2009. OG&E expects the impact of the rate increase on its customers and service territory to be minimal over the next 12 months as the rate increase will be more than offset by lower fuel costs attributable to prior fuel over recoveries and from lower than forecasted fuel costs in 2010.

OG&E Arkansas Rate Case Filing

In August 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 in the 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. On May 20, 2009, the APSC approved a general rate increase of approximately $13.3 million, which excludes approximately $0.3 million in storm costs discussed below. The APSC order 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. OG&E implemented the new electric rates effective June 1, 2009.

OG&E OU Spirit Wind Power Project

In July 2008, OG&E signed contracts for approximately 101 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with OU Spirit. As discussed below, OU Spirit is part of OG&E's goal to increase its wind power generation portfolio in the near future. On July 30, 2009, OG&E filed an application with the OCC requesting pre-approval to recover from Oklahoma customers the cost to construct OU Spirit at a cost of approximately $265.8 million. In November 2009, OG&E received an order from the OCC authorizing the recovery of up to $270 million of eligible construction costs, including recovery of the costs of the conservation project for the lesser prairie chicken as discussed below, through a rider mechanism as the 44 turbines were placed into service in November and December 2009 and began delivering electricity to OG&E's customers. The rider will be in effect until OU

Spirit is added to OG&E's regulated rate base as part of OG&E's next general rate case, which is expected to be based on a 2010 test year and completed in 2011, at which time the rider will cease. The order also assigns to OG&E's customers the proceeds from the sale of OU Spirit renewable energy credits to the University of Oklahoma. The rider was implemented on December 4, 2009 and the net impact of the rider on the average residential customer's 2010 electric bill is estimated to be approximately 90 cents per month, decreasing to 80 cents per month in 2011. Capital expenditures associated with this project were approximately $270 million.

In connection with OU Spirit, in January 2008, OG&E filed with the SPP for a Large Generator Interconnection Agreement ("LGIA") for this project. Since January 2008, the SPP has been studying this requested interconnection to determine the feasibility of the request, the impact of the interconnection on the SPP transmission system and the facilities needed to accommodate the interconnection. Given the backlog of interconnection requests at the SPP, there has been significant delay in completing the study process and in OG&E receiving a final LGIA. On May 29, 2009, OG&E executed an interim LGIA, allowing OU Spirit to interconnect into the transmission grid, subject to certain conditions. In connection with the interim LGIA, OG&E posted a letter of credit with the SPP of approximately $10.9 million, which was later reduced to approximately $9.9 million in October 2009 and further reduced to approximately $9.2 million in February 2010, related to the costs of upgrades required for OG&E to obtain transmission service from its new OU Spirit wind farm. The SPP filed the interim LGIA with the FERC on June 29, 2009. On August 27, 2009, the FERC issued an order accepting the interim LGIA, subject to certain conditions, which enables OU Spirit to interconnect into the transmission grid until the final LGIA can be put in place, which is expected by mid-2010.

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

OG&E Renewable Energy Filing

OG&E announced in October 2007 its goal to increase its wind power generation over the following four years from its then current 170 MWs to 770 MWs and, as part of this plan, on December 8, 2008, OG&E issued a request for proposal ("RFP") to wind developers for construction of up to 300 MWs of new capability which OG&E intends to add to its power-generation portfolio by the end of 2010. In June 2009, OG&E announced that it had selected a short list of bidders for a total of 430 MWs and that it was considering acquiring more than the approximately 300 MWs of wind energy originally contemplated in the initial RFP. On September 29, 2009, OG&E announced that, from its short list, it had reached agreements with two developers who are to build two new wind farms, totaling 280 MWs, in northwestern Oklahoma. Under the terms of the agreements, CPV Keenan is to build a 150 MW wind farm in Woodward County and Edison Mission Energy is to build a 130 MW facility in Dewey County near Taloga. The agreements are both 20-year power purchase agreements, under which the developers are to build, own and operate the wind generating facilities and OG&E will purchase their electric output. On October 30, 2009, OG&E filed separate applications with the OCC seeking pre-approval for the recovery of the costs associated with purchasing power from these projects. On December 9, 2009, all parties to these cases signed settlement agreements whereby the stipulating parties requested that the OCC issue orders: (i) finding that the execution of the power purchase agreements complied with the OCC competitive bidding rules, are prudent and are in the public's interest, (ii) approving the power purchase agreements and (iii) authorizing OG&E to recover the costs of the power purchase agreements through OG&E's fuel adjustment clause. On January 5, 2010, OG&E received an order from the OCC approving the power purchase agreements and authorizing OG&E to recover the costs of the power purchase agreements through OG&E's fuel adjustment clause. The two wind farms are expected to be in service by the end of 2010. Negotiations with the third bidder on OG&E's short list announced in June, for an additional 150 MWs of wind energy from Texas County were terminated in early October. OG&E will continue to evaluate renewable opportunities to add to its power-generation portfolio in the future.

OG&E Smart Grid Application

In February 2009, the President signed into law the ARRA. Several provisions of this law relate to issues of direct interest to the Company including, in particular, financial incentives to develop smart grid technology, transmission infrastructure and renewable energy. After review of the ARRA, OG&E filed a grant request on August 4, 2009 for $130 million with the DOE to be used for the Smart Grid application in OG&E's service territory. On October 27, 2009, OG&E received notification from the DOE that its grant had been accepted by the DOE for the full requested amount of $130 million. Receipt of the grant monies is contingent upon successful negotiations with the DOE on final details of the award. OG&E expects to file an application with the OCC requesting pre-approval for system-wide deployment of smart grid technology and a recovery rider, including a credit for the Smart Grid grant during the first quarter of 2010. Separately, on

November 30, 2009, OG&E requested a grant with a 50 percent match of up to $5 million for a variety of types of smart grid training for OG&E's workforce. Recipients of the grant are expected to be announced in the first quarter of 2010.

Agreement with Midcontinent Express Pipeline, LLC

In December 2006, Enogex entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC ("MEP") for a primary term of 10 years (subject to possible extension) that gives MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP lease agreement is currently 272 million cubic feet per day ("MMcf/d"), with the quantity ultimately to be leased subject to being increased by mutual agreement pursuant to the lease agreement. In addition to MEP's lease of Enogex's capacity, the MEP project included construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. In support of the MEP lease agreement, Enogex constructed approximately 43 miles of 24-inch steel pipe in Woods and Major counties in Oklahoma, and added 24,000 horsepower of electric-driven compression in Bennington, Oklahoma. Enogex's capital expenditures allocated to its support of the MEP lease agreement were approximately $99 million. Following receipt of the requested FERC authorization in 2008, Enogex proceeded with the construction of facilities necessary to implement this service. Subsequently, a protestor filed a request for a rehearing of the FERC authorization. The proceedings relating to the rehearing request are ongoing. For further information, please see Note 13 of Notes to Consolidated Financial Statements.

Enogex FERC Section 311 2009 Rate Case

Effective April 1, 2009, Enogex began offering firm Section 311 service in its East Zone. Offering this service required the filing of a new rate case at the FERC to establish rates for the firm service. Accordingly, on March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for its new firm East Zone Section 311 transportation service and to revise the rates for its existing East and West Zone interruptible Section 311 transportation service. In anticipation of offering this new service, Enogex had filed a revised Statement of Operating Conditions Applicable to Transportation Services ("SOC") with the FERC to describe the terms, conditions and operating arrangements for the new service.

The maximum rate for the new firm East Zone Section 311 transportation service was effective April 1, 2009. The revised zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for both the firm and interruptible Section 311 service are being collected, subject to refund, pending the FERC approval of the proposed rates. A number of parties intervened in both the rate case and the SOC filing and some additionally filed protests. Enogex has filed answers to the interventions and protests in both matters. On August 3, 2009, the FERC Staff served data requests on Enogex seeking additional information regarding various aspects of the filing. Enogex submitted responses to FERC Staff's data requests in August, September and October 2009. On August 19, 2009, the FERC issued an order extending the time for action until it can make a determination whether Enogex's rates are fair and equitable or until the FERC determines that formal proceedings are necessary. The August 19, 2009 order also directed the FERC Staff to report to the FERC by December 29, 2009 on the status of settlement negotiations. On January 4, 2010, the FERC Staff submitted its initial settlement offer ("Offer") proposing various adjustments to Enogex's filed cost of service. Comments in response to the FERC Staff's settlement offer were due on or before January 15, 2010. On January 14, 2010, Enogex asked the FERC Staff some clarifying questions regarding the Offer. Only Enogex and one intervenor filed comments on January 15, 2010, and each indicated that they were awaiting the FERC Staff's responses to the questions raised by Enogex before submitting substantive comments.

Gathering and Processing System Expansions

Southeastern Oklahoma / East Side Expansions

Enogex plans to construct a new compressor station in Coal County, Oklahoma, as well as approximately 10 miles of gathering pipe and related treating facilities. The station would be designed to accommodate up to 6,700 horsepower of low pressure compression and would be supported by approximately five miles of 20-inch steel pipe and five miles of 12-inch steel pipe. The new compressor station would also include the lease or possible purchase of associated gas treating facilities for the incremental gas in this area. The initial 2,700 horsepower at the compressor station, and the gathering pipe, are expected to be completed in February 2010, with an incremental 2,700 horsepower expected to be in service by April 2010. The capital expenditures for this construction are expected to be between approximately $18 million and $25 million depending on whether Enogex leases or purchases the equipment.

Texas Panhandle / West Side Expansions

In August 2009, Enogex added another 8,000 horsepower of low pressure compression in Wheeler County, Texas. The capital expenditures associated with the additional horsepower of low pressure compression were approximately $18 million.

Enogex completed construction of a new 120 MMcf/d cryogenic plant equipped with electric compression near Clinton, Oklahoma. This plant was placed in service in late October 2009 and is processing new gas developments in the area. In support of this plant, Enogex has installed approximately 15 miles of gathering pipe, 2.5 miles of transmission pipe, 10,000 horsepower of inlet compression, as well as other system upgrades. The capital expenditures associated with these projects were approximately $77 million.

As additional support for the strong production needs surrounding Enogex's new Clinton plant, Enogex plans to build an additional six miles of 16-inch high pressure gathering pipe and construct a new compressor station designed to handle 6,700 horsepower of single-stage compression. The initial 4,000 horsepower at the compressor station, and the high pressure gathering pipe, are expected to be in service in August 2010. The capital expenditures for this initial stage of the construction are expected to be approximately $14 million.

Enogex is planning to further expand its gathering infrastructure in 2010 in the Wheeler County, Texas area with the construction of approximately nine miles of 10-inch steel pipe and seven miles of 16-inch steel pipe, as well as the addition of approximately 2,700 horsepower of compression. The gathering pipelines are expected to be in service in May 2010, while the compression is expected to be operational by July 2010. The capital expenditures associated with this project are expected to be approximately $12 million.

Enogex is planning construction of approximately 26 miles of 16-inch steel pipe and five miles of 8-inch steel pipe located in Washita and Custer counties in Oklahoma. This project will provide additional high pressure gathering capacity to active producers in this growth area. This project is expected to be in service in September 2010. The capital expenditures associated with this project are expected to be approximately $19 million.

Enogex Additional Processing Capacity

In the fourth quarter of 2009, Enogex began taking delivery of components of a cryogenic processing plant which, when installed, will be expected to add another 120 MMcf/d of processing capacity to Enogex's system. The capital expenditures associated with the purchase of the new processing cryogenic plant are expected to be approximately $16 million and exclude any expenditures for installation and ancillary equipment.

Transportation System Expansions

In order to accommodate additional deliveries to Bennington, Oklahoma, Enogex is planning to add an incremental 13,800 horsepower of gas turbine compression at its Bennington compressor station, as well as other system upgrades. This project is expected to be in service in May 2010. The capital expenditures associated with these projects are expected to be approximately $24 million.

2010 Outlook

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

Key factors and assumptions for 2010 include:

Consolidated OGE Energy

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

OG&E

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

- Normal weather patterns are experienced for the year;
- Gross margin on revenues of approximately $1.05 billion to $1.06 billion. The key assumptions for gross margin are listed below:
  - Sales growth of approximately 0.9 percent on a weather adjusted basis; and
  - The Windspeed transmission line is in service with the rider effective April 1, 2010;
- Operating expenses of approximately $655 million to $665 million, with operation and maintenance expenses comprising approximately 60 percent of total;
- Interest expense of approximately $105 million to $115 million, which assumes approximately $250 million of additional long-term debt issued by OG&E in mid-2010;
- AEFUDC income of approximately $5 million; and
- An effective tax rate of approximately 27 percent.

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

Enogex

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

- Total Enogex anticipated gross margin of approximately $370 million to $400 million. The gross margin assumption includes:
  - Transportation and storage gross margin contribution of approximately $150 million to $160 million, of which approximately 20 percent is attributable to the storage business;
  - Gathering and processing gross margin contribution of approximately $220 million to $240 million, with equal contributions to gross margin from each business;
  - Key factors affecting the gathering and processing gross margin forecast are:
    - Assumed increase of five to seven percent in gathered volumes over 2009;
    - Assumed increase of 10 to 12 percent in inlet processing volumes over 2009;
    - At the midpoint of Enogex’s gathering and processing assumption Enogex has included:
      - Realized commodity spreads of $4.78 per Million British thermal unit (“MMBtu”) in 2010. The realized commodity spread takes into account that the majority of non-ethane processing volumes that bear price risk are hedged and the amortized cost of the hedges is included in the realized commodity spread calculation. Every 10 percent change in commodity spreads from $4.78 per MMBtu changes net income by approximately $4.0 million on an annual basis assuming all other margins remain static;
      - Natural gas price of $5.28 per MMBtu in 2010;
      - Realized weighted average NGLs price of $0.93 per gallon in 2010; and
      - Realized condensate spread of $7.81 per MMBtu in 2010;
- Operating expenses of approximately $220 million to $230 million, with operation and maintenance expenses comprising approximately 60 percent of total;
- Interest expense of approximately $30 million to $35 million; and
- An effective tax rate of approximately 39 percent.

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

Reconciliation of projected EBITDA to projected net income

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

(A) Based on midpoint of 2010 guidance.

For a discussion of the reasons for the use of EBITDA, as well as the limitations of EBITDA as an analytical tool, see "Enogex's Non-GAAP Financial Measure" below.

Dividend Policy

The Company's dividend policy is reviewed by the Board of Directors at least annually and is based on numerous factors, including management's estimation of the long-term earnings power of its businesses. The target payout ratio for the Company is to pay out as dividends no more than 60 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. At the Company's December 2009 Board meeting, management, after considering estimates of future earnings and numerous other factors, recommended to the Board of Directors an increase in the current quarterly dividend rate to $0.3625 per share from $0.3550 per share effective with the Company's first quarter 2010 dividend.

Results of Operations

The following discussion and analysis presents factors that affected the Company's consolidated results of operations for the years ended December 31, 2009, 2008 and 2007 and the Company's consolidated financial position at December 31, 2009 and 2008. The following information should be read in conjunction with the Consolidated Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

Year ended December 31 *(In millions, except per share data)*		**2009**		2008		2007
Operating income	**$**	**491.9**	$	462.1	$	455.3
Net income attributable to OGE Energy	**$**	**258.3**	$	231.4	$	244.2
Basic average common shares outstanding		**96.2**		92.4		91.7
Diluted average common shares outstanding		**97.2**		92.8		92.5
Basic earnings per average common share attributable to OGE Energy common shareholders	**$**	**2.68**	$	2.50	$	2.66
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$**	**2.66**	$	2.49	$	2.64
Dividends declared per share	**$**	**1.4275**	$	1.3975	$	1.3675

In reviewing its consolidated operating results, the Company believes that it is appropriate to focus on operating income as reported in its 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

Year ended December 31 *(In millions)*		**2009**		2008		2007
OG&E (Electric Utility)	**$**	**354.1**	$	278.3	$	292.0
Enogex (Natural Gas Pipeline)						
Transportation and storage		**85.7**		67.8		55.0
Gathering and processing		**60.2**		117.4		91.4
OERI (Natural Gas Marketing) (A)		**(7.5)**		6.4		17.1
Other Operations (B)		**(0.6)**		(7.8)		(0.2)
Consolidated operating income	**$**	**491.9**	$	462.1	$	455.3

(A) On January 1, 2008, Enogex distributed the stock of OERI to OGE Energy, and as a result, OERI is no longer a subsidiary of Enogex.
(B) 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 Consolidated Financial Statements.

OG&E (Electric Utility)

Year ended December 31 *(Dollars in millions)*	**2009**	2008	2007
Operating revenues	**$ 1,751.2**	$ 1,959.5	$ 1,835.1
Cost of goods sold	**796.3**	1,114.9	1,025.1
Gross margin on revenues	**954.9**	844.6	810.0
Other operation and maintenance	**348.0**	351.6	320.7
Depreciation and amortization	**187.4**	155.0	141.3
Impairment of assets	**0.3**	---	---
Taxes other than income	**65.1**	59.7	56.0
Operating income	**354.1**	278.3	292.0
Interest income	**1.1**	4.4	---
Allowance for equity funds used during construction	**15.1**	---	---
Other income	**20.4**	3.6	5.0
Other expense	**6.7**	11.8	7.2
Interest expense	**93.6**	79.1	54.9
Income tax expense	**90.0**	52.4	73.2
Net income	**$ 200.4**	$ 143.0	$ 161.7
Operating revenues by classification			
Residential	**$ 717.9**	$ 751.2	$ 706.4
Commercial	**439.8**	479.0	450.1
Industrial	**172.1**	219.8	221.4
Oilfield	**132.6**	151.9	140.9
Public authorities and street light	**167.7**	190.3	181.4
Sales for resale	**53.6**	64.9	68.8
Provision for rate refund	**(0.6)**	(0.4)	0.1
System sales revenues	**1,683.1**	1,856.7	1,769.1
Off-system sales revenues (A)	**31.8**	68.9	35.1
Other	**36.3**	33.9	30.9
Total operating revenues	**$ 1,751.2**	$ 1,959.5	$ 1,835.1
MWH (B) sales by classification (in millions)			
Residential	**8.7**	9.0	8.7
Commercial	**6.4**	6.5	6.3
Industrial	**3.6**	4.0	4.2
Oilfield	**2.9**	2.9	2.8
Public authorities and street light	**3.0**	3.0	3.0
Sales for resale	**1.3**	1.4	1.4
System sales	**25.9**	26.8	26.4
Off-system sales	**1.0**	1.4	0.7
Total sales	**26.9**	28.2	27.1
Number of customers	**776,550**	770,088	762,234
Average cost of energy per KWH (C) - cents			
Natural gas	**3.696**	8.455	6.872
Coal	**1.747**	1.153	1.143
Total fuel	**2.474**	3.337	3.173
Total fuel and purchased power	**2.760**	3.710	3.523
Degree days (D)			
Heating - Actual	**3,456**	3,394	3,175
Heating - Normal	**3,631**	3,650	3,631
Cooling - Actual	**1,860**	2,081	2,221
Cooling - Normal	**1,911**	1,912	1,911

(A) Sales to other utilities and power marketers.

(B) Megawatt-hour.

(C) Kilowatt-hour.

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

2009 compared to 2008. OG&E's operating income increased approximately $75.8 million in 2009 as compared to 2008 primarily due to a higher gross margin partially offset by higher depreciation and amortization expense.

Gross Margin

Gross margin was approximately $954.9 million in 2009 as compared to approximately $844.6 million in 2008, an increase of approximately $110.3 million, or 13.1 percent. The gross margin increased primarily due to:

- increased price variance, which included revenues from various rate riders, including the Redbud Facility rider, the storm cost recovery rider, the system hardening rider, the OU Spirit rider and the Oklahoma demand program rider, and higher revenues from the sales and customer mix, which increased the gross margin by approximately $89.5 million;
- the $48.3 million Oklahoma rate increase in which the majority of the annual increase is recovered during the summer months, which increased the gross margin by approximately $28.6 million;
- revenues from the Arkansas rate increase, which increased the gross margin by approximately $9.3 million;
- new customer growth in OG&E's service territory, which increased the gross margin by approximately $8.1 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 $1.8 million.

These increases in the gross margin were partially offset by:

- milder weather in OG&E's service territory, which decreased the gross margin by approximately $18.2 million; and
- lower demand and related revenues by non-residential customers in OG&E's service territory, which decreased the gross margin by approximately $8.1 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 $618.5 million in 2009 as compared to approximately $857.2 million in 2008, a decrease of approximately $238.7 million, or 27.8 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. In 2009, OG&E's fuel mix was 60 percent coal, 38 percent natural gas and two percent wind. In 2008, OG&E's fuel mix was 68 percent coal, 30 percent natural gas and two percent wind. Purchased power costs were approximately $176.6 million in 2009 as compared to approximately $257.0 million in 2008, a decrease of approximately $80.4 million, or 31.3 percent, primarily due to the termination of the purchase power agreement with the Redbud Facility following OG&E's purchase of the Redbud Facility in September 2008 as well as a decrease in purchases in the energy imbalance service market.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through fuel adjustment clauses. The fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex.

Operating Expenses

Other operation and maintenance expenses were approximately $348.0 million in 2009 as compared to approximately $351.6 million in 2008, a decrease of approximately $3.6 million, or 1.0 percent. The decrease in other operation and maintenance expenses was primarily due to:

- a decrease of approximately $13.2 million in contract technical and construction services attributable to decreased spending on overhauls at some of OG&E's power plants in 2009 as compared to 2008 and utilization of employees instead of contracting external labor;
- 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 Consolidated Financial Statements;
- an increase in capitalized labor in 2009 as compared to 2008, which decreased other operation and maintenance expenses by approximately $7.7 million;

- Ÿ a decrease of approximately $3.8 million in fleet transportation expense primarily due to lower fuel costs in 2009; and
- Ÿ a decrease of approximately $3.2 million due to the reclassification of 2006 and 2007 pension settlement costs to a regulatory asset due to the Arkansas rate case settlement, as discussed in Note 1 of Notes to Consolidated Financial Statements.

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

- Ÿ an increase of approximately $11.8 million in salaries and wages expense primarily due to salary increases in 2009 and increased incentive compensation expense in 2009;
- Ÿ an increase of approximately $7.2 million due to increased spending on vegetation management related to system hardening, which expenses are being recovered through a rider;
- Ÿ an increase of approximately $5.4 million in pension expense;
- Ÿ an increase of approximately $3.3 million due to OG&E's demand-side management initiatives, which expenses are being recovered through a rider;
- Ÿ an increase of approximately $2.2 million in medical and dental expenses; and
- Ÿ an increase of approximately $2.2 million in materials and supplies expense.

Depreciation and amortization expense was approximately $187.4 million in 2009 as compared to approximately $155.0 million in 2008, an increase of approximately $32.4 million, or 20.9 percent, primarily due to additional assets being placed into service, including the Redbud Facility that was placed into service in September 2008, and amortization of several regulatory assets.

Taxes other than income were approximately $65.1 million in 2009 as compared to approximately $59.7 million in 2008, an increase of approximately $5.4 million, or 9.1 percent, primarily due to higher ad valorem taxes.

Additional Information

Interest Income. Interest income was approximately $1.1 million in 2009 as compared to approximately $4.4 million in 2008, a decrease of approximately $3.3 million, or 75.0 percent, primarily due to interest from customers related to the fuel under recovery balance in 2008 and interest income from short-term investments.

Allowance for Equity Funds Used During Construction. AEFUDC was approximately $15.1 million in 2009. There was no AEFUDC in 2008. The increase in AEFUDC was primarily due to construction costs associated with OU Spirit and the Extra High Voltage ("EHV") Windspeed transmission line being constructed by OG&E.

Other Income. Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating income. Other income was approximately $20.4 million in 2009 as compared to approximately $3.6 million in 2008, an increase of approximately $16.8 million. Approximately $9.7 million of the increase in other income was related to the benefit associated with the tax gross-up of AEFUDC and approximately $5.9 million of the increase in other income was due to more customers participating in the guaranteed flat bill program and lower than expected usage resulting from milder weather in 2009 as compared to 2008.

Other Expense. Other expense includes, among other things, expenses from losses on the sale and retirement of assets, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions and expenses. Other expense was approximately $6.7 million in 2009 as compared to approximately $11.8 million in 2008, a decrease of approximately $5.1 million, or 43.2 percent, primarily due to 2008 write-downs of approximately $7.7 million for deferred costs associated with the cancelled Red Rock power plant and approximately $1.5 million associated with the 2007 and 2006 storm costs partially offset by an increase in charitable contributions of approximately $3.5 million.

Interest Expense. Interest expense was approximately $93.6 million in 2009 as compared to $79.1 million in 2008, an increase of approximately $14.5 million, or 18.3 percent. The increase in interest expense was primarily due to:

- Ÿ an increase of approximately $29.2 million in interest expense related to the issuances of long-term debt in 2008; and
- Ÿ an increase of approximately $2.0 million in interest expense due to interest to customers related to the fuel over recovery balance in 2009.

These increases in interest expense were partially offset by:

- a decrease in interest expense of approximately $8.9 million related to interest on short-term debt primarily due to lower short-term borrowings in 2009 due to the issuances of long-term debt by OG&E in 2008;
- a decrease in interest expense of approximately $4.3 million primarily due to a higher allowance for borrowed funds used during construction for capitalized interest; and
- a decrease in interest expense of approximately $2.4 million due to the settlement of treasury lock agreements OG&E entered into related to the issuance of long-term debt by OG&E in January 2008.

Income Tax Expense. Income tax expense was approximately $90.0 million in 2009 as compared to approximately $52.4 million in 2008, an increase of approximately $37.6 million, or 71.8 percent, primarily due to higher pre-tax income in 2009 as compared to 2008, lower Federal investment tax credit amortization and higher state income tax expense.

2008 compared to 2007. OG&E's operating income decreased approximately $13.7 million in 2008 as compared to 2007 primarily due to higher operation and maintenance expense, higher depreciation and amortization expense and higher taxes other than income partially offset by a higher gross margin.

Gross Margin

Gross margin was approximately $844.6 million in 2008 as compared to approximately $810.0 million in 2007, an increase of approximately $34.6 million, or 4.3 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 $21.1 million;
- new customer growth in OG&E's service territory, which increased the gross margin by approximately $8.4 million; and
- increased demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by approximately $5.0 million.

Fuel expense was approximately $857.2 million in 2008 as compared to approximately $756.1 million in 2007, an increase of approximately $101.1 million, or 13.4 percent, primarily due to higher 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. In 2008, OG&E's fuel mix was 68 percent coal, 30 percent natural gas and two percent wind. In 2007, OG&E's fuel mix was 62 percent coal, 36 percent natural gas and two percent wind. Purchased power costs were approximately $257.0 million in 2008 as compared to approximately $268.6 million in 2007, a decrease of approximately $11.6 million, or 4.3 percent, primarily due to lower purchases from the energy imbalance service market partially offset by capacity payments made to Redbud due to the purchase power agreement in effect prior to OG&E's purchase of the Redbud Facility in September 2008.

Operating Expenses

Other operation and maintenance expenses were approximately $351.6 million in 2008 as compared to approximately $320.7 million in 2007, an increase of approximately $30.9 million, or 9.6 percent. The increase in other operation and maintenance expenses was primarily due to:

- a decrease in capitalized work of approximately $14.0 million primarily related to costs related to the 2007 ice storm that were deferred as a regulatory asset;
- an increase 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 Consolidated Financial Statements;
- an increase of approximately $6.9 million in salaries and wages expense primarily due to hiring additional employees to support OG&E's operations as well as salary increases in 2008;
- an increase of approximately $6.6 million in contract technical and construction services expense and approximately $1.5 million in materials and supplies expense primarily attributable to overhaul expenses at several of OG&E's power plants in 2008;
- an increase of approximately $5.3 million due to increased spending on vegetation management;
- an increase of approximately $2.2 million in fleet transportation expense primarily due to higher fuel and maintenance costs in 2008; and

- an increase of approximately $1.3 million in professional services expense primarily due to higher engineering consulting services in 2008 as compared to 2007.

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

- lower allocations from OGE Energy of approximately $9.0 million due to lower pension and medical expenses and lower incentive compensation accruals;
- a decrease of approximately $4.0 million primarily due to overtime worked during the 2007 ice storm; and
- a decrease of approximately $3.0 million due to lower bad debt expense.

Depreciation and amortization expense was approximately $155.0 million in 2008 as compared to approximately $141.3 million in 2007, an increase of approximately $13.7 million or 9.7 percent, primarily due to additional assets being place into service, including the Redbud Facility that was placed into service in September 2008, and amortization of the Arkansas storm costs that are currently recorded as a regulatory asset.

Taxes other than income were approximately $59.7 million in 2008 as compared to approximately $56.0 million in 2007, an increase of approximately $3.7 million, or 6.6 percent, primarily due to higher ad valorem and payroll taxes.

Additional Information

Interest Income. Interest income was approximately $4.4 million in 2008. There was less than $0.1 million of interest income in 2007. The increase in interest income was primarily due to interest from customers related to the fuel under recovery balance in 2008 and interest income from short-term investments.

Other Income. Other income was approximately $3.6 million in 2008 as compared to approximately $5.0 million in 2007, a decrease of approximately $1.4 million, or 28.0 percent, primarily due to a lower gain on the guaranteed flat bill tariff due to higher than expected usage resulting from more customers participating in this program.

Other Expense. Other expense was approximately $11.8 million in 2008 as compared to approximately $7.2 million in 2007, an increase of approximately $4.6 million or 63.9 percent, primarily due to 2008 write-downs of approximately $7.5 million for deferred costs associated with the cancelled Red Rock power plant and approximately $1.5 million associated with the 2007 and 2006 storm costs. These increases in other expense were partially offset by a write-off of approximately $3.1 million associated with the cancelled Red Rock power plant for the Arkansas and the FERC jurisdictions during 2007.

Interest Expense. Interest expense was approximately $79.1 million in 2008 as compared to approximately $54.9 million in 2007, an increase of approximately $24.2 million, or 44.1 percent. The increase in interest expense was primarily due to:

- an increase of approximately $16.4 million in interest expense related to the issuances of long-term debt in 2008;
- an increase of approximately $7.2 million due to a settlement with the Internal Revenue Service ("IRS") resulting in a reversal of interest expense in 2007; and
- an increase of approximately $2.9 million in interest expense related to interest on short-term debt primarily due to increased commercial paper borrowings and revolving credit borrowings to fund the purchase of the Redbud Facility and daily operational needs of the Company.

These increases in interest expense were partially offset by a decrease of approximately $3.1 million in interest expense associated with the interest due to customers related to the fuel over recovery balance in 2007.

Income Tax Expense. Income tax expense was approximately $52.4 million in 2008 as compared to approximately $73.2 million in 2007, a decrease of approximately $20.8 million, or 28.4 percent, primarily due to lower pre-tax income in 2008 as compared to 2007 and an increase in Federal renewable energy credits and additional state income tax credits in 2008 as compared to 2007.

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

Year Ended December 31, 2009	Transportation and Storage	Gathering and Processing	Eliminations	Total
(In millions)				
Operating revenues	**$ 401.0**	**$ 657.5**	**$ (207.6)**	**$ 850.9**
Cost of goods sold	**239.9**	**458.8**	**(207.6)**	**491.1**
Gross margin on revenues	**161.1**	**198.7**	---	**359.8**
Other operation and maintenance	**40.9**	**87.2**	---	**128.1**
Depreciation and amortization	**20.4**	**43.9**	---	**64.3**
Impairment of assets	**0.9**	**1.9**	---	**2.8**
Taxes other than income	**13.2**	**5.5**	---	**18.7**
Operating income	**$ 85.7**	**$ 60.2**	**$ ---**	**$ 145.9**

Year Ended December 31, 2008	Transportation and Storage	Gathering and Processing	Eliminations	Total
(In millions)				
Operating revenues	$ 625.9	$ 1,053.2	$ (575.9)	$ 1,103.2
Cost of goods sold	479.7	806.4	(575.9)	710.2
Gross margin on revenues	146.2	246.8	---	393.0
Other operation and maintenance	48.2	87.3	---	135.5
Depreciation and amortization	17.5	37.1	---	54.6
Impairment of assets	---	0.4	---	0.4
Taxes other than income	12.7	4.6	---	17.3
Operating income	$ 67.8	$ 117.4	$ ---	$ 185.2

Year Ended December 31, 2007	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 529.1	$ 799.4	$ 1,541.2	$ (804.5)	$ 2,065.2
Cost of goods sold	396.4	603.5	1,513.4	(801.2)	1,712.1
Gross margin on revenues	132.7	195.9	27.8	(3.3)	353.1
Other operation and maintenance	48.5	72.1	10.1	(3.3)	127.4
Depreciation and amortization	17.0	28.7	0.2	---	45.9
Impairment of assets	0.5	---	---	---	0.5
Taxes other than income	11.7	3.7	0.4	---	15.8
Operating income	$ 55.0	$ 91.4	$ 17.1	$ ---	$ 163.5

Operating Data

Year Ended December 31	**2009**	2008	2007
Gathered volumes – TBtu/d (A)	**1.25**	1.16	1.05
Incremental transportation volumes – TBtu/d (B)	**0.54**	0.41	0.47
Total throughput volumes – TBtu/d	**1.79**	1.57	1.52
Natural gas processed – TBtu/d	**0.70**	0.66	0.57
Natural gas liquids sold (keep-whole) – million gallons	**110**	181	252
Natural gas liquids sold (purchased for resale) – million gallons	**351**	222	117
Natural gas liquids sold (percent-of-liquids) – million gallons	**32**	23	16
Total natural gas liquids sold – million gallons	**493**	426	385
Average sales price per gallon	**$ 0.770**	$ 1.255	$ 1.048
Estimated realized keep-whole spreads (C)	**$ 4.12**	$ 6.15	$ 5.35

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

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

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

2009 compared to 2008. Enogex's operating income decreased approximately $39.3 million in 2009 as compared to 2008 primarily due to lower processing spreads, lower NGLs prices and lower natural gas prices. The impact of the commodity price environment was partially offset by increased volumes and higher gallons per million cubic foot ("GPM") gas associated with expansion projects, the addition of the new higher efficiency Clinton processing plant which enabled Enogex to optimize recoveries across all processing plants, increased gathering rates, increased transportation fees associated with the implementation of the new Section 311 firm service, service under the MEP and Gulf Crossing capacity leases and increased capacity due to the addition of the Bennington compressor station. In the normal course of Enogex's business, the operation of its gathering, processing and transportation assets results in the creation of physical natural gas long/short positions. These physical positions can result from gas imbalances, actual versus contractual settlement differences, fuel tracker obligations and natural gas received in-kind for compensation or reimbursements. Enogex actively manages its monthly net position through either selling excess gas or purchasing additional gas needs from third parties. During 2009, higher volumes and realized margin on physical gas long/short positions increased the gross margin by approximately $9.2 million, net of corresponding imbalance and fuel tracker obligations. Also, in the normal course of Enogex's business, Enogex maintains natural gas inventory to provide operational support for its pipeline deliveries. All natural gas inventory held by Enogex is recorded at the lower of cost or market which could result in adjustments at the end of a reporting period.

Operation and maintenance expense decreased approximately $7.4 million primarily due to a reduction in spending on non-capitalized projects and lower employee expenses as a result of cost reduction efforts and an increase in capitalized labor associated with capital projects.

Depreciation and amortization increased approximately $9.7 million primarily due to property, plant and equipment placed into service during 2009. Taxes other than income increased approximately $1.4 million primarily due to an increase in ad valorem taxes.

Impairment of assets increased approximately $2.4 million due to the cancellation of certain projects as some producers reduced the level of drilling activity due to the downturn in the economic environment and the impairment of idle assets on which the determination was made that they will not be returned to service.

Transportation and Storage

The transportation and storage business contributed approximately $161.1 million of Enogex's consolidated gross margin in 2009 as compared to approximately $146.2 million in 2008, an increase of approximately $14.9 million, or 10.2 percent. The transportation operations contributed approximately $130.3 million of Enogex's consolidated gross margin in 2009 as compared to approximately $115.8 million in 2008. The storage operations contributed approximately $30.8 million of Enogex's consolidated gross margin in 2009 as compared to approximately $30.4 million in 2008. The transportation and storage operating income increased primarily due to:

- new capacity lease service under the MEP and Gulf Crossing capacity leases that were placed into service in the second quarter of 2009 that increased transportation fees by approximately $10.3 million;
- implementation of the new Section 311 firm East side service during the second quarter of 2009 that increased transportation fees by approximately $4.2 million;
- completion of the Bennington compressor station which increased take away capacity from the Enogex system and higher demand for crosshaul services as shippers bid up rates to move natural gas on the Enogex system during the first half of the 2009 that increased transportation fees by approximately $3.0 million, net of approximately $1.6 million for a potential rate refund pending the FERC approval of Enogex rates;
- higher seasonal spread values resulted in higher realized margins on operational storage hedges in 2009 as compared to 2008 that increased storage revenues by approximately $2.6 million;
- increased value of storage capacity due to the natural gas price volatility and seasonal spread values that increased storage fees by approximately $1.7 million;
- an approximate 8.6 percent volume increase primarily due to volumes from gathering expansion projects that increased transportation fees by approximately $1.4 million; and
- lower natural gas market prices and reduced injection and withdrawal activity reduced the valuation of the storage field losses by approximately $1.3 million.

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

- lower natural gas market prices resulting in the recognition of a lower of cost or market adjustment to the natural gas storage inventory of approximately $5.8 million in 2009 as compared to an adjustment of approximately $0.7 million in 2008, which decreased the gross margin by approximately $5.1 million;
- customer operational needs and contract renegotiations resulting in some customers transitioning from firm demand to interruptible services, which decreased transportation fees by approximately $2.2 million; and
- lower volumes and realized margin on sales of physical natural gas long/short positions associated with transportation operations decreased the gross margin by approximately $1.0 million, net of imbalance and fuel tracker obligations.

Operation and maintenance expense for the transportation and storage business was approximately $7.3 million, or 15.1 percent, lower in 2009 as compared to 2008 primarily due to an approximate $6.6 million reduction in spending for non-capitalized projects in 2009 and lower employee expenses of approximately $1.0 million as the result of cost reduction efforts. Also contributing to the lower operation and maintenance expenses was the reversal of a reserve of approximately $1.5 million in 2009 related to the dismissal of the Grynberg case as discussed in Note 13 of Notes to Consolidated Financial Statements. The reserve in this matter was originally established with the 1999 acquisition of Transok.

Gathering and Processing

The gathering and processing business contributed approximately $198.7 million of Enogex's consolidated gross margin in 2009 as compared to approximately $246.8 million in 2008, a decrease of approximately $48.1 million, or 19.5 percent. The gathering operations contributed approximately $114.0 million of Enogex's consolidated gross margin in 2009 as compared to approximately $90.9 million in 2008. The processing operations contributed approximately $84.7 million of Enogex's consolidated gross margin in 2009 as compared to approximately $155.9 million in 2008.

During 2009, Enogex realized a lower gross margin in its processing operations primarily as the result of lower processing spreads, lower market prices for NGLs and lower realized margins on contracts that were converted from keep-whole contracts to percent-of-liquids ("POL") and fixed-fee contracts in 2009. The impact of the overall market decline was partially offset by a 5.5 percent increase in inlet volumes associated with gathering expansion projects and an increase in the average GPM of gas being processed as recent expansion projects have added richer gas to the system. Additionally, completion of the new higher efficiency Clinton plant in late October 2009 allowed Enogex to optimize recoveries of gas processed at its Clinton, Cox City and Calumet processing plants increasing NGLs production. Overall, these factors resulted in the following:

- decreased gross margin on keep-whole processing of approximately $58.5 million;
- decreased gross margin on NGLs retained under POL contracts of approximately $9.5 million; and
- increased fixed processing fees of approximately $7.0 million.

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

- a decrease in condensate revenues by approximately $5.8 million associated with the gathering and processing operations due to decreases in prices partially offset by an increase in volumes due to several new expansion projects with higher GPM gas;
- lower natural gas market prices partially offset by a 9.4 percent increase in residue gas volumes associated with Atoka's operations that decreased the gross margin by approximately $5.6 million; and
- lower NGLs prices and an increase in utilization of third-party processing fees that decreased the Atoka processing gross margin by approximately $1.2 million.

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

- new volumes associated with gathering expansion projects that increased overall volumes by 7.7 percent resulting in increased gathering and treating fees by approximately $11.7 million; and
- higher volumes and realized margin on sales of physical natural gas long/short associated with gathering operations that increased the gross margin by approximately $10.2 million, net of imbalance and fuel tracker obligations.

Other operation and maintenance expense for the gathering and processing business was approximately $0.1 million, or 0.1 percent, lower in 2009 as compared to 2008 primarily due to overall costs reduction efforts offset by the additional operating and maintenance expense associated with the recent expansion projects.

Enogex Consolidated Information

Interest Income. Enogex's consolidated interest income was approximately $0.2 million in 2009 as compared to approximately $2.5 million in 2008, a decrease of approximately $2.3 million, or 92.0 percent, primarily due to lower investment levels and lower interest rates.

Interest Expense. Enogex's consolidated interest expense was approximately $35.7 million in 2009 as compared to approximately $32.7 million in 2008, an increase of approximately $3.0 million, or 9.2 percent. The increase in interest expense was primarily due to:

- an increase in interest expense of approximately $8.9 million on the $200 million of 6.875% 5-year senior notes issued in June 2009 and the $250 million of 6.25% 10-year senior notes issued in November 2009; and
- an increase in interest expense of approximately $3.0 million due to a tender payment on the tender offer Enogex completed in July 2009 for the purchase of approximately $110.8 million of Enogex's $400.0 million 8.125% senior notes outstanding that matured on January 15, 2010.

These increases in interest expense were partially offset by:

- lower interest expense of approximately $3.9 million due to the retirement in July 2009 of approximately $110.8 million of senior notes, which is a portion of Enogex's 8.125% senior notes due January 15, 2010;
- lower interest expense of approximately $2.7 million due to an increase in the amount of construction expenditures eligible for interest capitalization in 2009; and
- a decrease in interest expense of approximately $2.0 million due to a decrease in credit support fees.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was approximately $2.8 million in 2009 as compared to approximately $6.0 million in 2008, a decrease of approximately $3.2 million, or 53.3 percent, due to lower earnings related to Atoka.

Income Tax Expense. Enogex's consolidated income tax expense was approximately $40.8 million in 2009 as compared to approximately $57.3 million in 2008, a decrease of approximately $16.5 million, or 28.8 percent, primarily due to lower pre-tax income in 2009 as compared to 2008.

Non-recurring Items. Enogex had net income of approximately $66.3 million in 2009, which includes a net loss of approximately $0.8 million for items Enogex does not consider to be reflective of its ongoing operations. This decrease in Enogex's consolidated net income includes a tender payment on the tender offer Enogex completed in July 2009 of approximately $1.7 million after-tax for the purchase of approximately $110.8 million of Enogex's $400.0 million 8.125% senior notes that matured on January 15, 2010, which was partially offset by the reversal of a reserve of approximately $0.9 million after-tax in 2009 related to the dismissal of the Grynberg case as discussed in Note 13 of Notes to Consolidated Financial Statements.

2008 compared to 2007. Enogex's operating income increased approximately $21.7 million in 2008 as compared to 2007 primarily due to a higher gross margin in both the gathering and processing business and the transportation and storage business partially offset by higher operating expenses in both segments.

Gross Margin

Enogex's consolidated gross margin increased approximately $39.9 million in 2008 as compared to 2007. The increase resulted from a $50.9 million higher gross margin in the gathering and processing business and a $13.5 million higher gross margin in the transportation and storage business. Gross margin in 2007 included approximately $27.8 million attributable to OERI.

The transportation and storage business contributed approximately $146.2 million of Enogex's consolidated gross margin in 2008 as compared to approximately $132.7 million in 2007, an increase of approximately $13.5 million, or 10.2 percent. The transportation operations contributed approximately $115.8 million of Enogex's consolidated gross margin in 2008 as compared to approximately $97.8 million in 2007. The storage operations contributed approximately $30.4 million of Enogex's consolidated gross margin in 2008 as compared to approximately $34.9 million in 2007. The transportation and storage gross margin increased primarily due to:

- a decreased imbalance liability, net of fuel recoveries, electric compression costs and natural gas long/short positions, associated with the transportation operations in 2008, which increased the gross margin by approximately $16.3 million;
- increased crosshaul revenues as a result of a contract change in January 2008, that transferred revenues that had previously been classified as high pressure gathering revenues in 2007 as well as increased customer production in 2008, which increased the gross margin by approximately $4.9 million;
- administrative service fees received from OERI in 2008, which increased the gross margin by approximately $3.4 million; and
- increased low pressure revenues as a result of increased volumes primarily due to several new projects which began production in 2008, which increased the gross margin by approximately $2.1 million.

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

- Enogex's transportation operations moving from an under-recovered position to an over-recovered position under its FERC-approved fuel tracker in the East Zone in 2008, which resulted in a loss compared to a gain in 2007, which decreased the gross margin by approximately $8.0 million;
- lower gross margins on realized operational storage hedges in 2008 as compared to 2007, which decreased the gross margin by approximately $2.9 million;
- lower gross margins on commodity and interruptible storage fees resulting from the loss of a contract in 2008 and decreased activity due to changes in the marketplace, which decreased the gross margin by approximately $1.2 million; and
- the removal of a liability associated with a throughput contract which was transferred to the gathering and processing segment during 2007 with no comparable item recorded in 2008, which increased the 2007 gross margin by approximately $1.2 million.

The gathering and processing business contributed approximately $246.8 million of Enogex's consolidated gross margin in 2008 as compared to approximately $195.9 million in 2007, an increase of approximately $50.9 million, or 26.0 percent. The gathering operations contributed approximately $90.9 million of Enogex's consolidated gross margin in 2008 as compared to approximately $89.4 million in 2007. The processing operations contributed approximately $155.9 million of Enogex's consolidated gross margin in 2008 as compared to approximately $106.5 million in 2007. The gathering and processing gross margin increased primarily due to:

- an increase in keep-whole margins associated with the processing operations in 2008 as compared to 2007 primarily due to higher keep-whole margins throughout the majority of 2008, which increased the gross margin by approximately $16.8 million;
- an increase in the condensate margin associated with the processing operations due to higher prices and a 17.1 percent increase in volumes in 2008 as compared to 2007, which increased the gross margin by approximately $12.4 million;
- an increase in the POL gross margin associated with the processing operations due to: (i) favorable pricing for NGLs, as well an approximate 28.3 percent increase in volumes retained by Enogex, which increased the gross margin by approximately $10.8 million and (ii) new volumes from Atoka's processing operations, which began operations in August 2007, which increased the gross margin by approximately $3.2 million;
- higher compression and dehydration fees associated with the gathering operations resulting from new projects, including Atoka, in 2007 and 2008, which increased the gross margin by approximately $7.9 million;
- sales of residue gas, condensate and additional retained NGLs associated with the processing operations of Atoka, which began operations in August 2007, which increased the gross margin by approximately $6.8 million;
- an increase of natural gas processed under new and renegotiated fixed fee processing contracts, which increased the gross margin by approximately $4.0 million;
- increased low pressure gathering fees associated with new projects, including Atoka, which increased the gross margin by approximately $4.0 million; and
- the recognition of the liability associated with a throughput contract which was transferred from the transportation and storage segment in 2007 with no comparable item recorded 2008, which decreased the 2007 gross margin by approximately $1.9 million.

These increases in the gathering and processing business were partially offset by:

- Enogex moving from an under-recovered position to an over-recovered position in the East and West Zones in 2008, which resulted in a loss compared to the gain recognized in 2007, which decreased the gross margin approximately $7.2 million;
- an increased imbalance liability, net of fuel recoveries, electric compression costs and natural gas long/short positions in 2008, which decreased the gross margin by approximately $3.9 million; and
- increased costs for electric compression primarily due to the installation of a new compressor at one of Enogex's processing plants in 2008, which decreased the gross margin by approximately $1.7 million.

Operating Expenses

The aggregate of other operation and maintenance expense, depreciation and amortization expense, impairment of assets and taxes other than income was approximately $18.2 million higher in 2008 as compared to 2007. Depreciation and amortization expense increased approximately $8.7 million due to increased levels of depreciable plant in service. Taxes other than income increased approximately $1.5 million due to higher ad valorem taxes. Other operation and maintenance expense increased approximately $8.1 million primarily due to an increase in expenses for non-capitalized system projects, an increase in salaries, wages and benefits, increased allocations for overhead costs from OGE Energy and administrative service fees from OERI and higher equipment and compressor rental expense in 2008 as compared to 2007.

Specifically, by segment, other operation and maintenance expense for the transportation and storage business was approximately $0.3 million, or 0.6 percent, lower in 2008 as compared to 2007 primarily due to:

- higher internal allocations for overhead costs of approximately $3.0 million to the other Enogex segments, which decreased other operation and maintenance expense for the transportation and storage segment;
- lower contract professional, technical services and materials and supplies expense of approximately $1.3 million due to lower expenses on line remediation and non-capital pipeline integrity projects in 2008; and
- lower service expenses of approximately $1.1 million charged to the transportation and storage segment in 2008 by OERI due to a portion of the service fee being allocated to the gathering and processing segment in 2008.

These decreases in other operation and maintenance expense were partially offset by higher salaries, wages and other employee benefits expense of approximately $5.1 million primarily due to higher incentive compensation and hiring additional employees to support business growth.

Other operation and maintenance expense for the gathering and processing business was approximately $15.2 million, or 21.1 percent, higher in 2008 as compared to 2007 primarily due to:

- higher allocations for overhead and labor costs from the transportation and storage segment of approximately $6.6 million in 2008;
- higher contract professional services and materials and supplies expense of approximately $3.7 million due to an increase in non-capitalized system projects in 2008; and
- higher costs for compressor and equipment rental of approximately $1.7 million due to increased business in 2008.

Enogex Consolidated Information

Interest Income. Enogex's consolidated interest income was approximately $2.5 million in 2008 as compared to approximately $9.2 million in 2007, a decrease of approximately $6.7 million, or 72.8 percent, primarily due to a decrease in interest earned as the balance of advances to OGE Energy decreased due to dividends and capital expenditures.

Noncontrolling Interest. Enogex's consolidated noncontrolling interest was approximately $6.0 million in 2008 as compared to approximately $1.0 million in 2007, an increase of approximately $5.0 million primarily due to higher earnings related to Atoka.

Income Tax Expense. Enogex's consolidated income tax expense was approximately $57.3 million in 2008 as compared to approximately $53.5 million in 2007, an increase of approximately $3.8 million, or 7.1 percent, primarily due to higher pre-tax income in 2008 as compared to 2007.

Timing Items. In 2007, Enogex's consolidated net income was approximately $86.2 million, which included a loss of approximately $2.2 million resulting from recording OERI's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory were realized during the first and second quarters of 2008. On January 1, 2008, Enogex distributed its shares of common stock of OERI to OGE Energy.

OERI

Year Ended December 31 *(In millions)*	**2009**	2008	2007
Operating revenues	**$ 619.9**	$ 1,529.4	$ 1,541.2
Cost of goods sold	**617.7**	1,509.5	1,513.4
Gross margin on revenues	**2.2**	19.9	27.8
Other operation and maintenance	**9.2**	12.9	10.1
Depreciation and amortization	**0.1**	0.2	0.2
Taxes other than income	**0.4**	0.4	0.4
Operating income (loss)	**$ (7.5)**	$ 6.4	$ 17.1

2009 compared to 2008. OERI's operating loss was approximately $7.5 million in 2009 as compared to operating income of approximately $6.4 million in 2008, a decrease in operating income of approximately $13.9 million, primarily due to a lower gross margin partially offset by lower operation and maintenance expense.

Gross Margin

Gross margin was approximately $2.2 million in 2009 as compared to approximately $19.9 million in 2008, a decrease of approximately $17.7 million, or 88.9 percent. The gross margin decreased primarily due to:

- smaller differences in natural gas prices at various U.S. market locations which resulted a reduced spread that OERI was able to realize from delivering gas under its transportation contracts, which decreased the gross margin from transportation by approximately $7.2 million;
- the decrease in natural gas prices and NGLs spreads discussed above as well as selective deal execution in light of credit and other risks in the commodity price and credit environment in 2009 which resulted in limited opportunities for OERI in its customer focused risk management services and natural gas marketing activities, which decreased the gross margin by approximately $7.2 million; and
- a natural gas storage contract that ended in the second quarter of 2008 resulting in less storage capacity to manage in 2009, which decreased the gross margin from storage by approximately $3.3 million.

Operating Expenses

Other operation and maintenance expenses were approximately $9.2 million in 2009 as compared to approximately $12.9 million in 2008, a decrease of approximately $3.7 million, or 28.7 percent, primarily due to:

- the receipt of approximately $0.9 million from a bankruptcy settlement in 2009 for a bankruptcy that was recorded as a bad debt expense of approximately $1.5 million in 2008, resulting in a decrease in operation and maintenance expense of approximately $2.4 million; and
- a lower support service allocation of approximately $1.6 million from OGE Energy and Enogex in 2009.

Additional Information

Income Tax Expense (Benefit). Income tax benefit was approximately $3.1 million in 2009 as compared to income tax expense of approximately $2.9 million in 2008, an increase in the income tax benefit of approximately $6.0 million, primarily due to a pre-tax loss in 2009 as compared to pre-tax income in 2008.

2008 compared to 2007. OERI's operating income decreased approximately $10.7 million in 2008 as compared to 2007 primarily due to a lower gross margin and higher other operation and maintenance expense.

Gross Margin

Gross margin was approximately $19.9 million in 2008 as compared to approximately $27.8 million in 2007, a decrease of approximately $7.9 million, or 28.4 percent. The gross margin decreased primarily due to:

- lower realized gains associated with various transportation contracts in 2008 as compared to 2007, which decreased the gross margin by approximately $12.5 million;
- increased losses on economic hedges associated with various transportation contracts from recording these hedges at market value on December 31, 2008 as compared to recording these hedges at market value on December 31, 2007, which decreased the gross margin by approximately $6.8 million;
- a lower of cost or market adjustment to the natural gas storage inventory of approximately $6.2 million in 2008 as compared to an adjustment of approximately $3.6 million in 2007, which decreased the gross margin by approximately $2.6 million; and
- lower gains on physical sales of natural gas storage inventory activity partially offset by lower storage fees paid by OERI, which decreased the gross margin by approximately $2.5 million.

These decreases in the gross margin were partially offset by:

- gains on economic hedges associated with storage contracts from recording these hedges at market value on December 31, 2008 as compared to losses from recording these hedges at market value on December 31, 2007, which increased the gross margin by approximately $12.6 million; and
- increased gains from origination and other marketing and trading activity in 2008 as compared to 2007, which increased the gross margin by approximately $3.8 million.

Operating Expenses

Other operation and maintenance expenses were approximately $12.9 million in 2008 as compared to approximately $10.1 million in 2007, an increase of approximately $2.8 million, or 27.7 percent, primarily due to higher bad debt expense of approximately $1.5 million.

Additional Information

Income Tax Expense. Income tax expense was approximately $2.9 million in 2008 as compared to approximately $6.9 million in 2007, a decrease of approximately $4.0 million, or 58.0 percent, primarily due to lower pre-tax income in 2008 as compared to 2007.

Timing Items. In 2007, OERI's net income was approximately $10.9 million, which included a loss of approximately $2.2 million resulting from recording its natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory were realized during the first and second quarters of 2008.

Enogex's Non-GAAP Financial Measure

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

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

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

Reconciliation of EBITDA to net income attributable to Enogex LLC

Year Ended December 31 *(In millions)*		**2009**		2008		2007
Net income attributable to Enogex LLC (A)	**$**	**66.3**	$	91.2	$	86.2
Add:						
Interest expense, net		**35.5**		30.2		22.4
Income tax expense		**40.8**		57.3		53.5
Depreciation and amortization		**64.3**		54.6		45.9
EBITDA	**$**	**206.9**	$	233.3	$	208.0

(A) Approximately $10.9 million of net income attributable to Enogex LLC in 2007 was attributable to OERI.

There are no results for OERI included in the above table for 2008 or 2009 because, as of January 1, 2008, Enogex distributed the stock of OERI to OGE Energy.

Financial Condition

The balance of Cash and Cash Equivalents was approximately $58.1 million and $174.4 million at December 31, 2009 and 2008, respectively, a decrease of approximately $116.3 million, or 66.7 percent. See "Cash Flows" for a discussion of the changes in Cash and Cash Equivalents.

The balance of Accounts Receivable was approximately $291.4 million and $288.1 million at December 31, 2009 and 2008, respectively, an increase of approximately $3.3 million, or 1.1 percent, primarily due to an increase in volumes primarily due to Enogex's Clinton processing plant being placed in service in late October 2009 and NGLs prices at Enogex coupled with an increase in production from Enogex expansion projects that began production during 2008 and 2009 partially offset by decrease in OG&E's billings to customers from a lower fuel factor in 2009 as compared to 2008 related to lower natural gas prices as well as OG&E refunding approximately $80.4 million in fuel clause over recoveries to its Oklahoma customers over the next seven months as discussed below and a decrease in natural gas prices and volumes at OERI.

The balance of Income Taxes Receivable was approximately $157.7 million at December 31, 2009 with no balance at December 31, 2008, primarily due to an accrual of a tax benefit based on the Company's current estimates of a 2009 Federal tax net operating loss, a reclassification of the Federal tax benefit related to the estimated 2008 tax net operating loss from Accrued Taxes and a reclassification from Accumulated Deferred Income Taxes related to a change in the tax accounting method of accounting related to the capitalization of repair expenditures which was approved by the IRS in December 2009.

The balance of Fuel Inventories was approximately $118.5 million and $88.7 million at December 31, 2009 and 2008, respectively, an increase of approximately $29.8 million, or 33.6 percent, primarily due to a higher coal inventory balance due to higher average prices and planned outages at one of OG&E's coal-fired power plants partially offset by a lower natural gas inventory balance resulting from lower natural gas prices and volumes at Enogex.

The balance of Accumulated Deferred Tax Assets was approximately $39.8 million and $14.9 million at December 31, 2009 and 2008, respectively, an increase of approximately $24.9 million, primarily due to a reclassification from the Non-Current Accumulated Deferred Tax Asset to reflect the expected current deferred tax benefit of the Federal tax credit carryover balance at December 31, 2009.

The balance of Fuel Clause Under Recoveries was approximately $0.3 million and $24.0 million at December 31, 2009 and 2008, respectively, a decrease of approximately $23.7 million, or 98.8 percent, primarily due to the fact that the amount billed to retail customers was higher than OG&E's cost of fuel. The fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances.

The balance of Property, Plant and Equipment In Service was approximately $8,617.8 million and $7,722.4 million at December 31, 2009 and 2008, respectively, an increase of approximately $895.4 million, or 11.6 percent, primarily due to the transfer from Construction Work in Process of the costs associated with OU Spirit as the individual turbines were placed in service in November and December 2009 as well as other distribution and transmission projects at OG&E and various transportation, gathering and processing projects at Enogex being placed into service.

The balance of Construction Work in Process was approximately $335.4 million and $399.0 million at December 31, 2009 and 2008, respectively, a decrease of approximately $63.6 million, or 15.9 percent, primarily due to costs associated with OU Spirit being transferred to Property, Plant and Equipment In Service as the individual turbines were placed in service in November and December 2009 as well as assets being placed in service at Enogex in 2009 partially offset by the costs associated with the EHV Windspeed transmission line being constructed by OG&E.

The balance of Non-Current Price Risk Management Assets was approximately $4.3 million and $22.0 million at December 31, 2009 and 2008, respectively, a decrease of approximately $17.7 million, or 80.5 percent, primarily due to NGLs and keep-whole hedges moving from an asset to a liability position related to an increase in NGLs spreads in 2009.

The balance of Short-Term Debt was approximately $175.0 million and $298.0 million at December 31, 2009 and 2008, respectively, a decrease of approximately $123.0 million, or 41.3 percent, primarily due to the repayment of outstanding borrowings in 2009.

The balance of Customer Deposits was approximately $85.6 million and $58.8 million at December 31, 2009 and 2008, respectively, an increase of approximately $26.8 million, or 45.6 percent, primarily due to a customer's reimbursement of Enogex's costs related to the ongoing construction of a transportation pipeline in 2009.

The balance of Long-Term Debt Due Within One Year was approximately $289.2 million at December 31, 2009 with no balance at December 31, 2008, primarily due to the classification of Enogex's senior notes as a current liability as they mature on January 15, 2010. On July 23, 2009, Enogex purchased approximately $110.8 million of its $400.0 million 8.125% senior notes due January 15, 2010 and those repurchased notes were retired and cancelled (see Note 9 of Notes to Consolidated Financial Statements for a further discussion). The remaining balance of Enogex's senior notes of approximately $289.2 million at December 31, 2009 was repaid on January 15, 2010.

The balance of Fuel Clause Over Recoveries was approximately $187.5 million and $8.6 million at December 31, 2009 and 2008, respectively, an increase of approximately $178.9 million, primarily due to the fact that the amount billed to retail customers was higher than OG&E's cost of fuel. The fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances. As part of the OCC order in OG&E's Oklahoma rate case, OG&E will refund approximately $80.4 million in fuel clause over recoveries to its Oklahoma customers over the next seven months.

The balance of Other Current Liabilities was approximately $32.4 million and $62.2 million at December 31, 2009 and 2008, respectively, a decrease of approximately $29.8 million, or 47.9 percent, primarily due to a reduction in the liability for a storage agreement at OERI resulting from a withdrawal of natural gas from storage at the end of the contract term, a margin call payment to an OERI counterparty that was accrued at December 31, 2008 with no corresponding item at December 31, 2009, a payment for the liability for a margin sharing agreement at Enogex and a decrease in the liability for the OG&E off-system sales credit.

The balance of Accumulated Deferred Income Taxes was approximately $1,246.6 million and $996.9 million at December 31, 2009 and 2008, respectively, an increase of approximately $249.7 million, or 25.0 percent, primarily due to accelerated bonus tax depreciation which resulted in higher Federal and state deferred tax accruals partially offset by a reclassification to Income Taxes Receivable related to a change in the tax accounting method of accounting related to the capitalization of repair expenditures which was approved by the IRS in December 2009.

The balance of Accrued Removal Obligations, Net was approximately $168.2 million and $150.9 million at December 31, 2009 and 2008, respectively, an increase of approximately $17.3 million, or 11.5 percent, primarily due to the net removal accrual exceeding actual removal expense net of salvage.

The balance of Common Stockholders' Equity was approximately $887.7 million and $802.9 million at December 31, 2009 and 2008, respectively, an increase of approximately $84.8 million, or 10.6 percent, primarily due to the issuance of common stock through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan ("DRIP/DSPP") and compensation expense recorded in 2009 for non-vested performance units. See Notes 4 and 8 of Notes to Consolidated Financial Statements for a further discussion.

The balance of Retained Earnings was approximately $1,227.8 million and $1,107.6 million at December 31, 2009 and 2008, respectively, an increase of approximately $120.2 million, or 10.9 percent. See “Statement of Changes in Stockholders’ Equity” for a discussion of changes in Retained Earnings.

The balance of Accumulated Other Comprehensive Loss was approximately $74.7 million and $13.7 million at December 31, 2009 and 2008, respectively, an increase of approximately $61.0 million, primarily due to hedging losses at Enogex.

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

At December 31, 2009, OG&E had a noncancellable operating lease with purchase options, covering 1,462 coal hopper railcars to transport coal from Wyoming to OG&E’s coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E’s tariffs and fuel adjustment clauses. At the end of the lease term, which is January 31, 2011, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual 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 expired on November 2, 2009 and was not replaced.

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.

The Company’s consolidated estimates of capital expenditures are approximately: 2010 - $660 million, 2011 - $620 million, 2012 - $565 million, 2013 - $495 million, 2014 - $420 million and 2015 - $385 million. These capital expenditures represent the base maintenance capital expenditures (*i.e.*, capital expenditures to maintain and operate the Company’s businesses) plus capital expenditures for known and committed projects (collectively referred to as the “Base Capital Expenditure Plan”). Capital requirements and future contractual obligations estimated for the next five years and beyond are as follows:

(In millions)	Total	Less than 1 year (2010)	1-3 years (2011-2012)	3-5 years (2013-2014)	More than 5 years
Capital Expenditures					
OG&E Base Transmission	$ 150.0	$ 45.0	$ 40.0	$ 40.0	$ 25.0
OG&E Base Distribution	1,320.0	235.0	430.0	435.0	220.0
OG&E Base Generation	205.0	30.0	70.0	70.0	35.0
OG&E Other	150.0	25.0	50.0	50.0	25.0
Total OG&E Base Transmission, Distribution, Generation and Other	1,825.0	335.0	590.0	595.0	305.0
OG&E Known and Committed Projects:					
Transmission Projects:					
Sunnyside-Hugo (345 kV)	120.0	30.0	90.0	---	---
Sooner-Rose Hill (345 kV)	65.0	10.0	55.0	---	---
Windspeed (345 kV)	25.0	25.0	---	---	---
Balanced Portfolio 3E Projects	300.0	10.0	170.0	120.0	---
Total Transmission Projects	510.0	75.0	315.0	120.0	---
Other Projects:					
Smart Grid Program (A)	230.0	40.0	120.0	60.0	10.0
System Hardening	35.0	20.0	15.0	---	---
OU Spirit	10.0	10.0	---	---	---
Other	30.0	20.0	10.0	---	---
Total Other Projects	305.0	90.0	145.0	60.0	10.0
Total OG&E Known and Committed Projects	815.0	165.0	460.0	180.0	10.0
Total OG&E (B)	2,640.0	500.0	1,050.0	775.0	315.0
Enogex (Base Maintenance and Known and Committed Projects)	355.0	135.0	85.0	90.0	45.0
OGE Energy and OERI	150.0	25.0	50.0	50.0	25.0
Total capital expenditures	3,145.0	660.0	1,185.0	915.0	385.0
Maturities of long-term debt	2,384.6	289.2	---	300.0	1,795.4
Total capital requirements	5,529.6	949.2	1,185.0	1,215.0	2,180.4
Operating lease obligations					
OG&E railcars	41.9	3.9	38.0	---	---
Enogex noncancellable operating leases	4.5	2.5	2.0	---	---
Total operating lease obligations	46.4	6.4	40.0	---	---
Other purchase obligations and commitments					
OG&E cogeneration capacity payments	406.0	86.1	164.2	155.7	---
OG&E fuel minimum purchase commitments	426.0	340.0	84.2	1.8	---
OG&E wind minimum purchase commitments	948.9	10.2	103.3	104.8	730.6
OG&E long-term service agreements	141.3	3.7	28.4	37.9	71.3
OERI Cheyenne Plains commitments	30.8	5.4	10.8	13.0	1.6
OERI MEP commitments	9.2	2.1	4.2	2.9	---
Total other purchase obligations and commitments	1,962.2	447.5	395.1	316.1	803.5
Total capital requirements, operating lease obligations and other purchase obligations and commitments	7,538.2	1,403.1	1,620.1	1,531.1	2,983.9
Amounts recoverable through fuel adjustment clause (C)	(1,822.8)	(440.2)	(389.7)	(262.3)	(730.6)
Total, net	$ 5,715.4	$ 962.9	$ 1,230.4	$ 1,268.8	$ 2,253.3

(A) These capital expenditures are contingent upon OCC approval of OG&E's Positive Energy Smart Grid program and are net of the Smart Grid $130 million grant approved by the DOE.
(B) The Base Capital Expenditure Plan above excludes any environmental expenditures associated with Best Available Retrofit Technology ("BART") requirements due to the uncertainty regarding BART costs. As discussed in "– Environmental Laws and Regulations" below, pursuant to a proposed regional haze agreement OG&E has agreed to install low nitrogen oxide ("NOX") burners and related equipment at the three affected generating stations. Preliminary estimates indicate the cost will be approximately $100 million (plus or minus 30 percent). For further information, see "– Environmental Laws and Regulations" below.
(C) Includes expected recoveries of costs incurred for OG&E's railcar operating lease obligations, OG&E's cogeneration capacity payments, OG&E's unconditional fuel purchase obligations and OG&E's wind purchase commitments.
N/A – not available

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in transmission assets, wind generation assets and at Enogex, will be evaluated based upon their impact upon achieving the Company's financial objectives. The capital expenditure projections related to Enogex in the table above reflect base market conditions at February 17, 2010 and do not reflect the potential opportunity for a set of growth projects that could materialize.

OG&E also has approximately 720 MWs of contracts with qualified cogeneration facilities ("QF") and small power production producers ("QF contracts") to meet its current and future expected customer needs. OG&E will continue reviewing all of the supply alternatives to these QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates.

Variances in the actual cost of fuel used in electric generation (which includes the operating lease obligations for OG&E's railcar leases shown above) 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. Accordingly, while the cost of fuel related to operating leases and the vast majority of unconditional fuel purchase obligations of OG&E noted above may increase capital requirements, such costs are recoverable through fuel adjustment clauses and have little, if any, impact on net capital requirements and future contractual obligations. The fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC.

2009 Capital Requirements and Financing Activities

Total capital requirements, consisting of capital expenditures and maturities of long-term debt, were approximately $1,039.8 million and contractual obligations, net of recoveries through fuel adjustment clauses, were approximately $8.7 million resulting in total net capital requirements and contractual obligations of approximately $1,048.5 million in 2009. Approximately $2.1 million of the 2009 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $1,235.7 million and net contractual obligations of approximately $8.6 million totaling approximately $1,244.3 million in 2008, of which approximately $4.4 million was to comply with environmental regulations. During 2009, the Company's sources of capital were 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 DRIP/DSPP. Changes in working capital reflect the seasonal nature of the Company's business, the revenue lag between billing and collection from customers and fuel inventories. See "Financial Condition" for a discussion of significant changes in net working capital requirements as it pertains to operating cash flow and liquidity.

Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of approximately $289.2 million in 2010, which was repaid on January 15, 2010, and $200.0 million in 2014. There are no maturities of the Company's long-term debt in years 2011, 2012 or 2013.

Net Available Liquidity

At December 31, 2009, the Company had approximately $58.1 million of cash and cash equivalents. At December 31, 2009, the Company had approximately $1,049.8 million of net available liquidity under its revolving credit agreements.

Potential Collateral Requirements

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

Cash Flows

Year Ended December 31 *(In millions)*	**2009**	2008	2007
Net cash provided from operating activities	**$ 654.5**	$ 625.0	$ 328.5
Net cash used in investing activities	**(808.5)**	(1,184.1)	(556.3)
Net cash provided from financing activities	**37.7**	724.7	188.7

The increase of approximately $29.5 million in net cash provided from operating activities in 2009 as compared to 2008 was primarily due to:

- higher fuel recoveries at OG&E in 2009 as compared to 2008;
- cash received in 2009 from the implementation of the Redbud Facility rider in the third quarter of 2008;
- cash received in 2009 from the implementation of the Oklahoma rate increase in August 2009;
- payments made by OG&E in the first quarter of 2008 related to the December 2007 ice storm; and
- a decrease in payments for purchases at Enogex and OERI due to a decrease in natural gas prices and volumes in 2009 as compared to 2008.

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

- a decrease in cash receipts for sales at Enogex and OERI due to a decrease in natural gas prices and volumes in 2009 as compared to 2008; and
- a decrease in cash collateral posted by counterparties and held by OERI related to OERI's existing NGLs hedge positions.

The increase of approximately $296.5 million in net cash provided from operating activities in 2008 as compared to 2007 was primarily due to:

- higher fuel recoveries at OG&E in 2008 as compared to 2007;
- an increase in cash collateral received from counterparties related to OERI's existing NGLs hedge positions;
- an increase in payments for purchases at Enogex due to an increase in natural gas prices and volumes in 2008 as compared to 2007; and
- higher billed sales at OG&E in 2008.

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

- payments made by OG&E in the first quarter of 2008 related to the December 2007 ice storm; and
- an increase in cash receipts for sales at Enogex due to an increase in natural gas prices and volumes in 2008 as compared to 2007.

The decrease of approximately $375.6 million in net cash used in investing activities in 2009 as compared to 2008 primarily related to higher levels of capital expenditures in 2008 mostly related to the purchase of the Redbud Facility in September 2008 and various 2008 transportation, gathering and processing projects at Enogex partially offset by capital expenditures in 2009 related to OU Spirit and the EHV Windspeed transmission line being constructed by OG&E. Partially offsetting the decrease in net cash used in investing activities was a customer's reimbursement of Enogex's costs related to the ongoing construction of a transportation pipeline in 2009. The increase of approximately $627.8 million in net cash used in investing activities in 2008 as compared to 2007 primarily related to a higher level of capital expenditures mostly related to the purchase of the Redbud Facility in September 2008 and a higher level of capital expenditures at Enogex related to various 2008 transportation and gathering projects.

The decrease of approximately $687.0 million in net cash provided from financing activities in 2009 as compared to 2008 was primarily due to:

- proceeds received from the issuances of $700 million in long-term debt by OG&E in 2008;
- repayments of borrowings under Enogex's revolving credit agreement in 2009;
- repayments of short-term debt in 2009; and
- the purchase of approximately $110.8 million of Enogex's $400.0 million 8.125% senior notes related to the tender offer discussed below.

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

- proceeds received from the issuances of $450 million in long-term debt by Enogex in 2009; and
- an increase in the issuance of common stock in 2009.

The increase of approximately $536.0 million in net cash provided from financing activities in 2008 as compared to 2007 primarily related to proceeds received from the issuances of $700 million in long-term debt by OG&E in 2008 and an increase in proceeds from the line of credit primarily related to Enogex capital expenditures and the payment of a dividend to OGE Energy.

Future Capital Requirements and Financing Activities

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

On June 24, 2009, Enogex issued $200 million of 6.875% 5-year senior notes in a transaction exempt from the registration requirements of the Securities Act of 1933. Enogex applied a portion of the net proceeds from the sale of the new notes to pay the purchase price in a tender offer for its 8.125% notes due January 15, 2010 with the remainder of the net proceeds being used to repay a portion of the Company's borrowings under its revolving credit agreement and for general corporate purposes. Pursuant to the tender offer, on July 23, 2009, Enogex purchased approximately $110.8 million principal amount of the 8.125% senior notes due January 15, 2010 and those repurchased notes were retired and cancelled.

On November 10, 2009, Enogex issued $250 million of 6.25% 10-year senior notes in a transaction exempt from the registration requirements of the Securities Act of 1933. Enogex applied the net proceeds from the sale of the new notes to repay borrowings under its revolving credit agreement, with any excess net proceeds being invested at the OGE Energy level. Enogex's permanent use of the net proceeds from this debt issuance was to repay a portion of the $289.2 million outstanding aggregate principal amount of Enogex's 8.125% senior notes, which matured on January 15, 2010. On January 15, 2010, the $289.2 million outstanding aggregate principal amount of Enogex's 8.125% senior notes was repaid.

Pension and Postretirement Benefit Plans

In October 2009, the Company's qualified defined benefit retirement plan ("Pension Plan") and the Company's qualified defined contribution retirement plan ("401(k) Plan") were amended, effective December 31, 2009, to offer a one-time irrevocable election for eligible employees, depending on their hire date, to select a future retirement benefit combination from the Company's Pension Plan and the Company's 401(k) Plan. Also, all employees hired prior to February 1, 2000 participate in the Company's defined benefit postretirement plans. See Note 11 of Notes to the Consolidated Financial Statements for a further discussion.

At December 31, 2009, approximately 49.4 percent of the pension plan assets were invested in listed common stocks with the balance invested in corporate debt and U.S. Government securities. In 2009, asset returns on the Pension Plan increased approximately 22.9 percent from a decrease of approximately 25.1 percent in 2008 due to the decline in the equity market in 2008. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline. The Company could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future. During each of 2009 and 2008, the Company made contributions to its Pension Plan of approximately $50.0 million to help ensure that the Pension Plan maintains an adequate funded status. The level of funding is dependent on returns on plan assets and future discount rates. During 2010, the Company may contribute up to $50.0 million to its Pension Plan.

The Company recorded a pension settlement charge and a retirement restoration plan settlement charge in 2007. The pension settlement charge and retirement restoration plan settlement charge did not require a cash outlay by the Company and did not increase the Company's total pension expense or retirement restoration expense over time, as the charges were an acceleration of costs that otherwise would have been recognized as pension expense or retirement restoration expense in future periods.

(In millions)	OG&E (A)	Enogex	OGE Energy	Total
Pension Settlement Charge:				
2007	$ 13.3	$ 0.5	$ 2.9	$ 16.7
Retirement Restoration Plan Settlement Charge:				
2007	$ 0.1	$ ---	$ 2.2	$ 2.3

(A) OG&E's Oklahoma and Arkansas jurisdictional portion of these charges were recorded as a regulatory asset (see Note 1 of Notes to Consolidated Financial Statements for a further discussion).

At December 31, 2009, the projected benefit obligation and fair value of assets of the Company's Pension Plan and restoration of retirement income plan was approximately $619.2 million and $496.3 million, respectively, for an underfunded status of approximately $122.9 million. Also, at December 31, 2009, the accumulated postretirement benefit obligation and fair value of assets of the Company's postretirement benefit plans was approximately $288.0 million and $55.0 million, respectively, for an underfunded status of approximately $233.0 million. The above amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1 of Notes to Consolidated Financial Statements) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

At December 31, 2008, the projected benefit obligation and fair value of assets of the Company's Pension Plan and restoration of retirement income plan was approximately $554.3 million and $389.9 million, respectively, for an underfunded status of approximately $164.4 million. Also, at December 31, 2008, the accumulated postretirement benefit obligation and fair value of assets of the Company's postretirement benefit plans was approximately $234.3 million and $57.0 million, respectively, for an underfunded status of approximately $177.3 million. The above amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1 of Notes to Consolidated Financial Statements) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

Pension Plan Costs and Assumptions

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the "Pension Protection Act") into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Many of the changes enacted as part of the Pension Protection Act were required to be implemented as of the first plan year beginning in 2008. The Company has implemented all of the required changes as part of the Pension Protection Act as discussed in Note 11 of Notes to Consolidated Financial Statements.

Security Ratings

	Moody's	Standard & Poor's	Fitch's
OG&E Senior Notes	A2	BBB+	AA-
Enogex Notes	Baa3	BBB+	BBB
OGE Energy Corp. Senior Notes	Baa1	BBB	A
OGE Energy Corp. Commercial Paper	P2	A2	F1

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Future financing requirements may be dependent, to varying degrees, upon numerous factors such as general economic conditions, abnormal weather, load growth, commodity prices, levels of drilling activity, acquisitions of other businesses and/or development of projects, actions by rating agencies, inflation, changes in environmental laws or regulations, rate increases or decreases allowed by regulatory agencies, new legislation and market entry of competing electric power generators.

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 DRIP/DSPP 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 capital expenditures until permanent financing is arranged.

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was approximately $175.0 million and $298.0 million at December 31, 2009 and 2008, respectively. The December 31, 2009 short-term debt balance of approximately $175.0 million is comprised entirely of outstanding commercial paper borrowings at OGE Energy. The December 31, 2008 short-term debt balance of approximately $298.0 million is comprised entirely of outstanding borrowings under OGE Energy's revolving credit agreement. At December 31, 2009, there were no outstanding borrowings under Enogex's revolving credit agreement. At December 31, 2008, Enogex had approximately $120.0 million in outstanding borrowings under its revolving credit agreement. The following table provides information regarding the Company's revolving credit agreements and available cash at December 31, 2009.

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

Entity	Aggregate Commitment	Amount Outstanding	Weighted-Average Interest Rate	Maturity
OGE Energy	$ 596.0	$ 175.0	0.27%	December 6, 2012
OG&E	389.0	10.2	0.14%	December 6, 2012
Enogex	250.0	---	---%	March 31, 2013
	1,235.0	185.2	0.26%	
Cash	58.1	N/A	N/A	N/A
Total	$ 1,293.1	$ 185.2	0.26%	

OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any time for a two-year period beginning January 1, 2009 and ending December 31, 2010. See Note 10 of Notes to the Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Registration Statement Filing

During the first half of 2010, the Company expects to file a Form S-3 Registration Statement to register debt and equity securities for sale by the Company and OG&E.

Expected Issuance of OG&E Long-Term Debt

OG&E expects to issue approximately $250 million of long-term debt in mid-2010, depending on market conditions, to fund capital expenditures, repay short-term borrowings and for general corporate purposes.

Common Stock

The Company expects to issue between approximately $12 million and $15 million in its DRIP/DSPP in 2010. See Note 8 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

Income Tax Refund

As discussed in Note 7 of Notes to Consolidated Financial Statements, OG&E filed a request with the IRS on December 29, 2008 for a change in its tax method of accounting related to the capitalization of repair expenditures. On December 10, 2009, OG&E received approval from the IRS for the change in accounting method. In December 2009, a claim for refund was filed to carry back the 2008 tax loss resulting in a tax refund of approximately $81.8 million, which OG&E received in February 2010. The expected refund was recorded in Income Taxes Receivable on the Consolidated Balance Sheet at December 31, 2009.

Critical Accounting Policies and Estimates

The Consolidated Financial Statements and Notes to Consolidated Financial Statements contain information that is pertinent to Management's Discussion and Analysis. In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, impairment estimates, contingency reserves, asset retirement obligations ("ARO"), fair value and cash flow hedges, regulatory assets and liabilities, unbilled revenues for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable and the valuation of purchase and sale contracts. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's Audit Committee.

Consolidated (including all Company segments)

Pension and Postretirement Benefit Plans

The Company has a Pension Plan that covers substantially all of the Company's employees hired before December 1, 2009. Also, effective December 1, 2009, the Company's Pension Plan is no longer being offered to employees hired on or after December 1, 2009. The Company also has defined benefit postretirement plans that cover substantially all of its employees. Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and the level of funding. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized. The pension plan rate assumptions are shown in Note 11 of Notes to Consolidated Financial Statements. The assumed return on plan assets is based on management's expectation of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and an increase in discount rates will reduce funding requirements to the pension plan. The following table indicates the sensitivity of the pension plan funded status to these variables.

	Change	Impact on Funded Status
Actual plan asset returns	+/- 5 percent	+/- $24.8 million
Discount rate	+/- 0.25 percent	+/- $19.4 million
Contributions	+ $10.0 million	+ $10.0 million
Expected long-term return on plan assets	+/- 1 percent	None

Impairment of Assets

The Company assesses potential impairments of assets or asset groups when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset or asset group. For purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Estimates of future cash flows used to test the recoverability of a long-lived asset or asset group shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset or asset group. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. The Company recorded impairments of approximately $3.1 million, $0.4 million and $0.5 million in 2009, 2008 and 2007, respectively.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. 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 Consolidated Financial Statements.

Except as otherwise disclosed in this Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Notes 13 and 14 of Notes to Consolidated Financial Statements and Item 3 in this Form 10-K.

Asset Retirement Obligations

In the fourth quarter of 2009, OG&E recorded an ARO for approximately $4.5 million related to its OU Spirit wind farm. Beginning January 1, 2010, OG&E will amortize the remaining value of the related ARO asset over the estimated remaining life of 35 years. The Company also has other previously recorded AROs that are being amortized over their respective lives ranging from 20 to 99 years. The Company also has certain AROs that have not been recorded because the Company determined that these assets, primarily related to Enogex's processing plants and compression sites and OG&E's power plant sites, have indefinite lives.

Hedging Policies

The Company engages in cash flow hedge transactions to manage commodity risk. The Company may hedge its forward exposure to manage the impact of changes in commodity prices. Hedges of anticipated transactions are documented as cash flow hedges and are executed based upon management-established price targets. During 2007, 2008 and 2009, Enogex applied hedge accounting to account for hedges of contractual long/short positions, natural gas purchases and sales and keep-whole natural gas and NGLs hedges. Maturities of Enogex's commodity hedging positions at December 31, 2009 occur in 2010 through 2011. OERI applied hedge accounting to manage commodity exposure for certain transportation and natural gas inventory hedges. Maturities of OERI's commodity hedging positions at December 31, 2009 do not extend beyond the first quarter of 2010. Hedges are evaluated prior to execution with respect to the impact on the volatility of forecasted earnings and are evaluated at least quarterly after execution for the impact on earnings.

OG&E and Enogex engage in cash flow and fair value hedge transactions to modify the rate composition of the debt portfolio. During 2007, OG&E entered into treasury lock agreements relating to managing interest rate exposure on the debt portfolio or anticipated debt issuances to modify the interest rate exposure on fixed rate debt issues. These treasury lock agreements qualified as cash flow hedges with an objective to protect against the variability of future interest payments of long-term debt that was issued by OG&E. The Company does not currently have any outstanding treasury lock agreements.

Electric Utility Segment

Regulatory Assets and Liabilities

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

OG&E records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates. The benefits obligation regulatory asset is comprised of items which are probable of future recovery that have not yet been recognized as a component of net periodic benefit cost including, net loss, prior service cost and net transition obligation.

Unbilled Revenues

OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. At December 31, 2009, if the estimated usage or price used in the unbilled revenue calculation were to increase or decrease by one percent, this would cause a change in the unbilled revenues recognized of approximately $0.4 million. At December 31, 2009 and 2008, Accrued Unbilled Revenues were approximately $57.2 million and $47.0 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. Beginning in August 2009 and going forward, there was a change in the provision calculation as a result of the Oklahoma rate case whereby the portion of the uncollectible provision related to fuel will be recovered through the fuel adjustment clause. At December 31, 2009, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of approximately $0.2 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was approximately $1.7 million and $2.3 million at December 31, 2009 and 2008, respectively.

Natural Gas Transportation and Storage and Gathering and Processing Segments

Operating Revenues

Operating revenues for gathering, processing, transportation and storage services for Enogex are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Operating revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated operating revenues are reflected in Accounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income.

Enogex recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold.

Natural Gas Purchases

Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

Natural Gas Inventory

Natural gas inventory is held by Enogex and is valued using moving average cost. Enogex maintains natural gas inventory to provide operational support for its pipeline deliveries. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2009 and 2008, Enogex recorded write-downs to market value related to natural gas storage inventory of approximately $5.8 million and $0.7 million, respectively. Enogex did not record a write-down to market value related to natural gas storage inventory during 2007. The amount of Enogex's natural gas inventory was approximately $10.2 million and $16.2 million at December 31, 2009 and 2008, respectively. The cost of gas associated with sales of natural gas storage inventory is presented in Cost of Goods Sold on the Consolidated Statements of Income.

Allowance for Uncollectible Accounts Receivable

The allowance for uncollectible accounts receivable is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when Enogex believes the collection of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The aggregate allowance for uncollectible accounts receivable for the transportation and storage and gathering and processing segments was approximately $0.7 million and $0.9 million at December 31, 2009 and 2008, respectively.

Marketing Segment

Operating Revenues

OERI engages in energy marketing, trading, risk management and hedging activities related to the purchase and sale of natural gas as well as hedging activity related to the sale of natural gas and NGLs on behalf of the Company. Contracts utilized in these activities generally include purchases and sales for physical delivery of natural gas, over-the-counter forward swap and option contracts and exchange traded futures and options. OERI's transactions that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as Price Risk Management ("PRM") assets or liabilities in the Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement, or against the brokerage deposits in Other Current Assets. The offsetting unrealized gains and losses from changes in the market value of open contracts are included in Operating Revenues in the Consolidated Statements of Income or in Other Comprehensive Income for derivatives designated and qualifying as cash flow hedges. Contracts resulting in delivery of a commodity are included as sales or purchases in the Consolidated Statements of Income as Operating Revenues or Cost of Goods Sold depending on whether the contract relates to the sale or purchase of the commodity.

Operating revenues for physical delivery of natural gas are recorded the month of physical delivery based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Estimated operating revenues are reflected in Accounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income.

Natural Gas Purchases

Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

Purchase and Sale Contracts

OERI utilizes energy purchases and sales for physical delivery of natural gas and financial instruments including over-the-counter forward swap and option contracts and exchange traded futures and options. The majority of these activities qualify as derivatives and are recorded at fair market value. OERI's portfolio is marked to estimated fair market value on a daily basis. When available, actual market prices are utilized in determining the value of natural gas and related derivative commodity instruments. For longer-term positions, which are limited to a maximum of 60 months and certain short-term position for which market prices are not available, models based on forward price curves are utilized. These models incorporate estimates and assumptions as to a variety of factors such as pricing relationships between various energy commodities and geographic location. Actual experience can vary significantly from these estimates and assumptions.

In nearly all cases, independent market prices are obtained and compared to the values used in determining the fair value, and an oversight group outside of the marketing organization monitors all modeling methodologies and assumptions. The recorded value of the energy contracts may change significantly in the future as the market price for the commodity changes, but the value of transactions not designated as cash flow hedges is subject to mark-to-market risk loss limitations provided under the Company's risk policies. Management utilizes models to estimate the fair value of the Company's energy contracts including derivatives that do not have an independent market price. At December 31, 2009, unrealized mark-to-market gains were approximately $2.4 million, none of which were calculated utilizing models. At December 31, 2009, a price movement of one percent for prices verified by independent parties would result in unrealized mark-to-market gains or losses of less than $0.1 million and a price movement of five percent on model-based prices would result in unrealized mark-to-market gains or losses of less than $0.1 million.

Natural Gas Inventory

As part of its recurring buy and sell activity, OERI injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. In an effort to mitigate market price exposures, OERI enters into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by OERI is recorded at the lower of cost or market. During 2009, 2008 and 2007, OERI recorded write-downs to market value related to natural gas storage inventory of approximately $0.3 million, $6.2 million and $3.6 million, respectively. The amount of OERI's natural gas inventory was approximately $7.3 million and $15.9 million at December 31, 2009 and 2008, respectively. The cost of gas associated with sales of natural gas storage inventory is presented in Cost of Goods Sold on the Consolidated Statements of Income.

Allowance for Uncollectible Accounts Receivable

The allowance for uncollectible accounts receivable is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when OERI believes the collection of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The aggregate allowance for uncollectible accounts receivable was less than $0.1 million at both December 31, 2009 and 2008.

Accounting Pronouncements

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

Commitments and Contingencies

Except as disclosed otherwise in this Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Notes 13 and 14 of Notes to Consolidated Financial Statements and Item 3 of Part I in this Form 10-K for a discussion of the Company's commitments and contingencies.

Environmental Laws and Regulations

The activities of OG&E and Enogex are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators, regulating future construction activities to avoid endangered species or enjoining some or all of the operations of facilities deemed in noncompliance with permits issued pursuant to such environmental laws and regulations. In most instances, the applicable regulatory requirements relate to water and air pollution control or solid waste management measures. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes can impose burdensome liability for costs required to clean up and restore sites where substances or wastes have been disposed or otherwise released into the environment. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment. OG&E and Enogex handle some materials subject to the requirements of the Federal Resource Conservation and Recovery Act and the Federal Water Pollution Control Act of 1972, as amended ("Federal Clean Water Act") and comparable state statutes, prepare and file reports and documents pursuant to the Toxic Substance Control Act and the Emergency Planning and Community Right to Know Act and obtain permits pursuant to the Federal Clean Air Act and comparable state air statutes.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's or Enogex's facilities. Historically, OG&E's and Enogex's total expenditures for environmental control facilities and for remediation have not been significant in relation to its consolidated financial position or results of operations. The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards may increase the cost of conducting business.

Approximately $3.5 million and $3.9 million, respectively of the Company's capital expenditures budgeted for 2010 and 2011 are to comply with environmental laws and regulations. The Company's management believes that all of its operations are in substantial compliance with present Federal, state and local environmental standards. It is estimated that the Company's total expenditures for capital, operating, maintenance and other costs associated with environmental quality will be approximately $26.6 million during 2010 as compared to approximately $24.0 million in 2009. Management continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position itself in a competitive market.

Air

Federal Clean Air Act

OG&E's and Enogex's operations are subject to the Federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including electric generating units, natural gas processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that OG&E and Enogex obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, install emission control equipment or subject OG&E and Enogex to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. OG&E and Enogex likely will be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions.

Mercury and Hazardous Air Pollutants

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. In January 2010, the EPA issued an information collection request which will survey power plant operators about their emissions of mercury and other hazardous air pollutants ("HAP"). The EPA has announced plans to promulgate new HAP emission limitations for coal-fired and oil-fired power plants by November 2011. Any costs associated with future regulation of mercury or other HAPs are uncertain at this time. Because of the uncertainty caused by the litigation regarding the CAMR, the promulgation of an Oklahoma rule that would have applied to existing facilities has also been delayed. OG&E will continue to participate in the state rule making process.

RICE MACT Amendments

On March 5, 2009, the EPA initiated rulemaking concerning new national emission standards for hazardous air pollutants for existing reciprocating internal combustion engines by proposing amendments to the National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engine Maximum Achievable Control Technology ("RICE MACT Amendments"). Depending on the final regulations that may be enacted by the EPA for the RICE MACT Amendments, Enogex and OG&E facilities will likely be impacted. The costs that may be incurred to comply with these regulations, including the testing and modification of the affected engines, are uncertain at this time. The current proposed compliance deadline is three years from the effective date of the final rules.

Regional Haze

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

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

Waivers were not available for the BART-eligible units at the Seminole, Muskogee and Sooner generating stations. OG&E submitted a BART compliance plan for Seminole on March 30, 2007 committing to installation of NOX controls on all three units. On May 30, 2008, OG&E filed BART evaluations for the affected generating units at the Muskogee and Sooner generating stations. In this filing, OG&E indicated its intention to install low NOX combustion technology at its affected generating stations and to continue to burn low sulfur coal at the four coal-fired generating units at its Muskogee and Sooner generating stations. OG&E did not propose the installation of scrubbers at these four coal-fired generating units because OG&E concluded that, consistent with the EPA's regulations on BART, the installation of scrubbers (at an estimated cost of more than $1.0 billion) would not be cost-effective. The original deadline for the ODEQ to submit a SIP for regional haze that includes final BART determinations was December 17, 2007. The ODEQ did not meet this deadline. On January 15, 2009, the EPA published a rule that gives the ODEQ two years to complete the SIP. If the ODEQ fails to meet this deadline, the EPA can issue a Federal implementation plan. The draft SIP was published by the ODEQ for public review on November 13, 2009. This draft SIP suggested that scrubbers would be needed to comply with the regional haze regulations, but noted OG&E's cost-effectiveness analysis. Following negotiations with the ODEQ, OG&E submitted in February 2010 a proposed agreement to the ODEQ (the "Proposed Agreement") which specifies that BART for reducing NOX emissions at all seven BART-eligible units at the Seminole, Muskogee and Sooner generating stations should be the installation of low NOX burners with overfire air (and flue gas recirculation on two of the affected units) and accompanying emission rate and annual emission tonnage limits. Preliminary estimates based on recent industry experience and cost projections estimate the total cost of the NOX-related equipment at the three affected generating stations at approximately $100 million (plus or minus 30 percent). After OG&E obtains estimates from vendors based on a detailed engineering design, it will have a more firm estimate of the exact cost of the NOX-related equipment subject to changes in the cost of basic materials. Under the Proposed Agreement, the specified BART for reducing sulfur dioxide ("SO2") at the four coal-fired units at the Muskogee and Sooner generating stations would be continued use of low sulfur coal and emission rate and annual emission tonnage limits consistent with such use of low sulfur coal. Implementation of these BART requirements would be achieved within five years of the EPA's approval of Oklahoma's regional haze SIP.

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

OG&E expects that the ODEQ will sign the Proposed Agreement and will include the agreement in the final SIP that is submitted to the EPA for approval. It is anticipated that the EPA will take final action on the SIP for regional haze during the first quarter of 2011. OG&E cannot predict what action the EPA will take.

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

Sulfur Dioxide

The 1990 Federal Clean Air Act includes an acid rain program to reduce SO2 emissions. Reductions were obtained through a program of emission (release) allowances issued by the EPA to power plants covered by the acid rain program. Each allowance is worth one ton of SO2 released from the chimney. Plants may only release as much SO2 as they have allowances. Allowances may be banked and traded or sold nationwide. Beginning in 2000, OG&E became subject to more stringent SO2 emission requirements in Phase II of the acid rain program. These lower limits had no significant financial impact due to OG&E's earlier decision to burn low sulfur coal. In 2009, OG&E's SO2 emissions were below the allowable limits.

On November 16, 2009, the EPA proposed a new one-hour National Ambient Air Quality Standard ("NAAQS") for SO_2 to address public health concerns. The EPA is proposing to revise the primary SO_2 standard to a level of between 50 and 100 parts per billion ("PPB") measured over one-hour. The EPA is under a consent decree to take final action by June 2, 2010. The proposal was published in the Federal Register on December 8, 2009. Oklahoma is in attainment with the current three-hour and 24-hour SO_2 NAAQS; however, a one-hour standard less than 100 PPB may result in certain areas not meeting attainment. If parts of Oklahoma do become "non-attainment", reductions in emissions from OG&E's coal-fired boilers could be required, which may result in significant capital and operating expenditures.

Ozone

On January 7, 2010, the EPA announced a proposal to set the "primary" standard for ozone at a level between 0.06 and 0.07 parts per million measured over eight hours. The EPA is also proposing to set a separate "secondary" standard to protect the environment, especially plants and trees. The deadline for submitting comments on the proposal is March 22, 2010. The EPA has also proposed an accelerated schedule for designating areas for the primary ozone standard and is accepting comments on whether to designate areas for a seasonal secondary standard on an accelerated schedule or a two-year schedule. Following area designations by the EPA, expected to become effective August 2011, the proposed schedule would require submittal by December 2013 of state implementation plans that outline how the state will reduce pollution to meet the ambient standard. The state would be required to meet the primary standard, with deadlines depending on the severity of the problem, between 2014 and 2031. The Company cannot predict the final outcome of this evaluation or its timing or affect on OG&E's or Enogex's operations.

Greenhouse Gases

There also is growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation and regulation at the Federal level, actions at the state level, litigation relating to greenhouse gas emissions and pressure for greenhouse gas emission reductions from investor organizations and the international community. Recently, two Federal courts of appeal have reinstated nuisance-type claims against emitters of carbon dioxide, including several utility companies, alleging that such emissions contribute to global warming. Although the Company is not a defendant in either proceeding, additional litigation in Federal and state courts over these issues is expected.

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

On December 15, 2009, the EPA published their finding that greenhouse gases contribute to air pollution that may endanger public health or welfare. Although the endangerment finding is being made in the context of greenhouse gas emissions from new motor vehicles, the finding is likely to result in other forms of regulation. Numerous petitions are pending at the EPA from various state and environmental groups seeking regulation of a variety of mobile sources (*i.e.*, trucks, airplanes, ships, boats, equipment, etc.) and stationary sources. With the endangerment finding issued, the EPA is likely to begin acting on these petitions in 2010. Additionally, on December 2, 2009 the Center for Biological Diversity announced a petition with the EPA seeking promulgation of a greenhouse gas NAAQS.

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

Legislation

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

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

Water

Section 316(b) of the Federal 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. Permits required for existing facilities are to be developed by the individual states using their best professional judgment until the EPA takes action to address several court decisions addressing previous rules and confirming that EPA has discretion to consider costs relative to benefits in developing cooling water intake structure regulations. On January 7, 2008, OG&E submitted to the state of Oklahoma a comprehensive demonstration study for each affected facility. At the Company's request, Oklahoma will not require implementation of 316(b) requirements prior to the EPA developing and finalizing their rules. When there are final rules implemented by the state, OG&E may require additional capital and/or increased operating costs associated with cooling water intake structures at its generating facilities.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Market risks are, in most cases, risks that are actively traded in a marketplace and have been well studied in regards to quantification. Market risks include, but are not limited to, changes in commodity prices, commodity price volatilities and interest rates. The Company is exposed to commodity price and commodity price volatility risks in its operations. The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt, treasury lock agreements and commercial paper. The Company engages in PRM activities for both trading and non-trading purposes.

Risk Committee and Oversight

Management monitors market risks using a risk committee structure. The Company's Risk Oversight Committee, which consists primarily of corporate officers, is responsible for the overall development, implementation and enforcement of strategies and policies for all risk management activities of the Company. This committee's emphasis is a holistic perspective of risk measurement and policies targeting the Company's overall financial performance. The Risk Oversight Committee is authorized by, and reports quarterly to, the Audit Committee of the Company's Board of Directors.

The Unregulated Business Unit Risk Management Committee is comprised primarily of business unit leaders within Enogex and OERI. This committee's purpose is to develop and maintain risk policies for the unregulated entities, to provide oversight and guidance for existing and prospective unregulated business activities and to provide governance regarding compliance with unregulated risk policies. This group is authorized by and reports to the Risk Oversight Committee.

The Company also has a Corporate Risk Management Department led by the Company's Chief Risk Officer. This group, in conjunction with the aforementioned committees, is responsible for establishing and enforcing the Company's risk policies.

Risk Policies

Management utilizes risk policies to control the amount of market risk exposure. These policies are designed to provide the Audit Committee of the Company's Board of Directors and senior executives of the Company with confidence that the risks taken on by the Company's business activities are in accordance with their expectations for financial returns and that the approved policies and controls related to risk management are being followed. Some of the measures in these policies include value-at-risk ("VaR") limits, position limits, tenor limits and stop loss limits.

Interest Rate Risk

The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt, treasury lock agreements and commercial paper. 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. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce interest expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

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. At December 31, 2009 and 2008, the Company had no outstanding treasury lock agreements. The following table shows the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

Year ended December 31 *(Dollars in millions)*	2010	2011	2012	2013	2014	Thereafter	Total	12/31/09 Fair Value
Fixed-rate debt (A)								
Principal amount	$ 289.2	$ ---	$ ---	$ ---	$ 300.0	$ 1,660.0	$ 2,249.2	$ 2,341.4
Weighted-average interest rate	8.13%	---	---	---	6.25%	6.57%	6.73%	---
Variable-rate debt (B)								
Principal amount	---	---	---	---	---	$ 135.4	$ 135.4	$ 135.4
Weighted-average interest rate	---	---	---	---	---	0.57%	0.57%	---

(A) Prior to or when these debt obligations mature, the Company may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt.
(B) A hypothetical change of 100 basis points in the underlying variable interest rate would change interest expense by approximately $1.4 million annually.

Commodity Price Risk

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

Trading Activities

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

A sensitivity analysis has been prepared to estimate the Company's exposure to market risk created by trading activities. The value of trading positions is a summation of the fair values calculated for each net commodity position based upon quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in quoted market prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows at:

December 31 *(In millions)*	**2009**	2008
Commodity market risk, net	**$ 0.4**	$ 0.1

Non-Trading Activities

The prices of natural gas and NGLs, and NGLs processing spreads, are subject to fluctuations resulting from changes in supply and demand. The changes in these prices have a direct effect on the compensation the Company receives for operating some of its assets. To partially reduce non-trading commodity price risk, the Company utilizes risk mitigation tools such as default processing fees and ethane rejection capabilities to protect its downside exposure while maintaining its upside potential. Additionally, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the Company's operating income. Because the commodities covered by these hedges are substantially the same commodities that the Company buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

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

A sensitivity analysis has been prepared to estimate the Company's exposure to the market risk of the Company's non-trading activities. The Company's daily net commodity position consists of natural gas inventories, commodity purchase and sales contracts, financial and commodity derivative instruments and anticipated natural gas processing spreads and fuel recoveries. Quoted market prices are not available for all of the Company's non-trading positions; therefore, the value of non-trading positions is a summation of the forecasted values calculated for each commodity based upon internally generated forward price curves. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in such prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows at:

December 31 *(In millions)*	**2009**	2008
Commodity market risk, net	**$ 17.0**	$ 6.6

The increase in downside commodity market risk reflected in the table above is primarily due to favorable commodity price conditions at December 31, 2009 as compared to December 31 2008. These favorable conditions increased the Company's per unit exposure. During 2009, the Company reduced its volumetric exposure to commodity market risk by converting a portion of its agreements from commodity market based compensation to fixed-fee based compensation. Absent these conversions, the commodity market risk at December 31, 2009 would have been even greater.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 (In millions, except per share data)	**2009**	2008	2007
OPERATING REVENUES			
Electric Utility operating revenues	**$ 1,751.2**	$ 1,959.5	$ 1,835.1
Natural Gas Pipeline operating revenues	**1,118.5**	2,111.2	1,962.5
Total operating revenues	**2,869.7**	4,070.7	3,797.6
COST OF GOODS SOLD (exclusive of depreciation and amortization shown below)			
Electric Utility cost of goods sold	**748.7**	1,061.2	977.8
Natural Gas Pipeline cost of goods sold	**809.0**	1,756.8	1,656.9
Total cost of goods sold	**1,557.7**	2,818.0	2,634.7
Gross margin on revenues	**1,312.0**	1,252.7	1,162.9
Other operation and maintenance	**466.8**	492.2	436.8
Depreciation and amortization	**262.6**	217.5	195.3
Impairment of assets	**3.1**	0.4	0.5
Taxes other than income	**87.6**	80.5	75.0
OPERATING INCOME	**491.9**	462.1	455.3
OTHER INCOME (EXPENSE)			
Interest income	**1.4**	6.7	2.1
Allowance for equity funds used during construction	**15.1**	---	---
Other income	**27.5**	15.4	17.4
Other expense	**(16.3)**	(25.6)	(22.7)
Net other income (expense)	**27.7**	(3.5)	(3.2)
INTEREST EXPENSE			
Interest on long-term debt	**137.3**	103.0	87.8
Allowance for borrowed funds used during construction	**(8.3)**	(4.0)	(4.0)
Interest on short-term debt and other interest charges	**8.4**	21.0	6.4
Interest expense	**137.4**	120.0	90.2
INCOME BEFORE TAXES	**382.2**	338.6	361.9
INCOME TAX EXPENSE	**121.1**	101.2	116.7
NET INCOME	**261.1**	237.4	245.2
Less: Net income attributable to noncontrolling interest	**2.8**	6.0	1.0
NET INCOME ATTRIBUTABLE TO OGE ENERGY	**$ 258.3**	$ 231.4	$ 244.2
BASIC AVERAGE COMMON SHARES OUTSTANDING	**96.2**	92.4	91.7
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**97.2**	92.8	92.5
BASIC EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	**$ 2.68**	$ 2.50	$ 2.66
DILUTED EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	**$ 2.66**	$ 2.49	$ 2.64
DIVIDENDS DECLARED PER SHARE	**$ 1.4275**	$ 1.3975	$ 1.3675

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2009**	2008
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 58.1**	$ 174.4
Accounts receivable, less reserve of $2.4 and $3.2, respectively	**291.4**	288.1
Accrued unbilled revenues	**57.2**	47.0
Income taxes receivable	**157.7**	---
Fuel inventories	**118.5**	88.7
Materials and supplies, at average cost	**78.4**	72.1
Price risk management	**1.8**	11.9
Gas imbalances	**3.2**	6.2
Accumulated deferred tax assets	**39.8**	14.9
Fuel clause under recoveries	**0.3**	24.0
Prepayments	**8.7**	9.0
Other	**11.0**	8.3
Total current assets	**826.1**	744.6
OTHER PROPERTY AND INVESTMENTS, at cost	**43.7**	42.2
PROPERTY, PLANT AND EQUIPMENT		
In service	**8,617.8**	7,722.4
Construction work in progress	**335.4**	399.0
Total property, plant and equipment	**8,953.2**	8,121.4
Less accumulated depreciation	**3,041.6**	2,871.6
Net property, plant and equipment	**5,911.6**	5,249.8
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**19.1**	14.6
Benefit obligations regulatory asset	**357.8**	344.7
Price risk management	**4.3**	22.0
McClain Plant deferred expenses	---	6.2
Unamortized loss on reacquired debt	**16.5**	17.7
Unamortized debt issuance costs	**15.3**	13.5
Other	**72.3**	63.2
Total deferred charges and other assets	**485.3**	481.9
TOTAL ASSETS	**$ 7,266.7**	$ 6,518.5

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2009**	2008
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 175.0**	$ 298.0
Accounts payable	**297.0**	279.7
Dividends payable	**35.1**	33.2
Customer deposits	**85.6**	58.8
Accrued taxes	**37.0**	26.8
Accrued interest	**60.6**	48.7
Accrued compensation	**50.1**	45.2
Long-term debt due within one year	**289.2**	---
Price risk management	**14.2**	2.3
Gas imbalances	**12.0**	24.9
Fuel clause over recoveries	**187.5**	8.6
Other	**32.4**	62.2
Total current liabilities	**1,275.7**	888.4
LONG-TERM DEBT	**2,088.9**	2,161.8
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**369.3**	350.5
Accumulated deferred income taxes	**1,246.6**	996.9
Accumulated deferred investment tax credits	**13.1**	17.3
Accrued removal obligations, net	**168.2**	150.9
Price risk management	**0.1**	3.8
Other	**44.0**	34.9
Total deferred credits and other liabilities	**1,841.3**	1,554.3
Total liabilities	**5,205.9**	4,604.5
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**887.7**	802.9
Retained earnings	**1,227.8**	1,107.6
Accumulated other comprehensive loss, net of tax	**(74.7)**	(13.7)
Total OGE Energy stockholders' equity	**2,040.8**	1,896.8
Noncontrolling interest	**20.0**	17.2
Total stockholders' equity	**2,060.8**	1,914.0
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 7,266.7**	$ 6,518.5

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*		**2009**	2008
STOCKHOLDERS' EQUITY			
Common stock, par value $0.01 per share; authorized 125.0 shares; and outstanding 97.0 and 93.5 shares, respectively		**$ 1.0**	$ 0.9
Premium on capital stock		**886.7**	802.0
Retained earnings		**1,227.8**	1,107.6
Accumulated other comprehensive loss, net of tax		**(74.7)**	(13.7)
Total OGE Energy stockholders' equity		**2,040.8**	1,896.8
Noncontrolling interest		**20.0**	17.2
Total stockholders' equity		**2,060.8**	1,914.0
LONG-TERM DEBT			
SERIES	DATE DUE		
Senior Notes - OGE Energy Corp.			
5.00%	Senior Notes, Series Due November 15, 2014	**100.0**	100.0
Unamortized discount		**(0.5)**	(0.5)
Senior Notes - OG&E			
5.15%	Senior Notes, Series Due January 15, 2016	**110.0**	110.0
6.50%	Senior Notes, Series Due July 15, 2017	**125.0**	125.0
6.35%	Senior Notes, Series Due September 1, 2018	**250.0**	250.0
8.25%	Senior Notes, Series Due January 15, 2019	**250.0**	250.0
6.65%	Senior Notes, Series Due July 15, 2027	**125.0**	125.0
6.50%	Senior Notes, Series Due April 15, 2028	**100.0**	100.0
6.50%	Senior Notes, Series Due August 1, 2034	**140.0**	140.0
5.75%	Senior Notes, Series Due January 15, 2036	**110.0**	110.0
6.45%	Senior Notes, Series Due February 1, 2038	**200.0**	200.0
Other Bonds - OG&E			
0.30% - 1.00%	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
0.42% - 0.74%	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
0.42% - 0.75%	Muskogee Industrial Authority, June 1, 2027	**56.0**	55.9
Unamortized discount		**(3.6)**	(3.9)
Enogex			
8.125%	Senior Notes, Series Due January 15, 2010	**289.2**	400.0
---%	Enogex Revolving Credit Agreement Due March 31, 2013	**---**	120.0
6.875%	Senior Notes, Series Due July 15, 2014	**200.0**	---
6.25%	Senior Notes, Series Due March 15, 2020	**250.0**	---
Unamortized discount		**(2.4)**	---
Unamortized swap monetization		**---**	0.9
Total long-term debt		**2,378.1**	2,161.8
Less long-term debt due within one year		**289.2**	---
Total long-term debt (excluding long-term debt due within one year)		**2,088.9**	2,161.8
Total Capitalization		**$ 4,149.7**	$ 4,075.8

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(In millions)	Common Stock	Premium on Capital Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance at December 31, 2006	$ 0.9	$ 740.1	$ 890.8	$ (28.0)	$ ---	$ 1,603.8
Comprehensive income (loss)						
Net income for 2007	---	---	244.2	---	1.0	245.2
Other comprehensive income (loss), net of tax						
Defined benefit pension plan and restoration of retirement income plan:						
Net loss, net of tax ($4.4 pre-tax)	---	---	---	2.7	---	2.7
Prior service cost, net of tax ($5.4 pre-tax)	---	---	---	3.3	---	3.3
Defined benefit postretirement plans:						
Net loss, net of tax ($3.3 pre-tax)	---	---	---	1.7	---	1.7
Net transition obligation, net of tax ($0.2 pre-tax)	---	---	---	0.1	---	0.1
Prior service cost, net of tax ($0.5 pre-tax)	---	---	---	0.3	---	0.3
Deferred hedging losses, net of tax (($100.0) pre-tax)	---	---	---	(61.3)	---	(61.3)
Amortization of cash flow hedge, net of tax ($0.4 pre-tax)	---	---	---	0.2	---	0.2
Other comprehensive loss	---	---	---	(53.0)	---	(53.0)
Comprehensive income (loss)	---	---	244.2	(53.0)	1.0	192.2
Dividends declared on common stock	---	---	(125.5)	---	---	(125.5)
Adoption of new accounting principle (($6.2) pre-tax) (A)	---	---	(3.8)	---	---	(3.8)
Contribution from noncontrolling interest partner	---	---	---	---	9.7	9.7
Issuance of common stock	---	15.2	---	---	---	15.2
Balance at December 31, 2007	$ 0.9	$ 755.3	$ 1,005.7	$ (81.0)	$ 10.7	$ 1,691.6
Comprehensive income (loss)						
Net income for 2008	---	---	231.4	---	6.0	237.4
Other comprehensive income (loss), net of tax						
Defined benefit pension plan and restoration of retirement income plan:						
Net loss, net of tax (($42.2) pre-tax)	---	---	---	(25.8)	---	(25.8)
Prior service cost, net of tax ($0.5 pre-tax)	---	---	---	0.3	---	0.3
Defined benefit postretirement plans:						
Net loss, net of tax (($2.6) pre-tax)	---	---	---	(1.6)	---	(1.6)
Net transition obligation, net of tax ($0.3 pre-tax)	---	---	---	0.2	---	0.2
Prior service cost, net of tax ($0.3 pre-tax)	---	---	---	0.2	---	0.2
Deferred hedging gains, net of tax ($153.3 pre-tax)	---	---	---	93.8	---	93.8
Amortization of cash flow hedge, net of tax ($0.4 pre-tax)	---	---	---	0.2	---	0.2
Other comprehensive income	---	---	---	67.3	---	67.3
Comprehensive income	---	---	231.4	67.3	6.0	304.7
Dividends declared on common stock	---	---	(129.5)	---	---	(129.5)
Contribution from noncontrolling interest partner	---	---	---	---	0.5	0.5
Issuance of common stock	---	46.7	---	---	---	46.7
Balance at December 31, 2008	**$ 0.9**	**$ 802.0**	**$ 1,107.6**	**$ (13.7)**	**$ 17.2**	**$ 1,914.0**
Comprehensive income (loss)						
Net income for 2009	---	---	**258.3**	---	**2.8**	**261.1**
Other comprehensive income (loss), net of tax						
Defined benefit pension plan and restoration of retirement income plan:						
Net loss, net of tax ($6.2 pre-tax)	---	---	---	**3.8**	---	**3.8**
Prior service cost, net of tax (($0.3) pre-tax)	---	---	---	**(0.2)**	---	**(0.2)**
Defined benefit postretirement plans:						
Net loss, net of tax (($8.8) pre-tax)	---	---	---	**(5.4)**	---	**(5.4)**
Net transition obligation, net of tax ($0.2 pre-tax)	---	---	---	**0.1**	---	**0.1**
Prior service cost, net of tax ($0.3 pre-tax)	---	---	---	**0.2**	---	**0.2**
Deferred hedging losses, net of tax (($97.7) pre-tax)	---	---	---	**(59.8)**	---	**(59.8)**
Amortization of cash flow hedge, net of tax ($0.5 pre-tax)	---	---	---	**0.3**	---	**0.3**
Other comprehensive loss	---	---	---	**(61.0)**	---	**(61.0)**
Comprehensive income (loss)	---	---	**258.3**	**(61.0)**	**2.8**	**200.1**
Dividends declared on common stock	---	---	**(138.1)**	---	---	**(138.1)**
Issuance of common stock	**0.1**	**84.7**	---	---	---	**84.8**
Balance at December 31, 2009	**$ 1.0**	**$ 886.7**	**$1,227.8**	**$ (74.7)**	**$ 20.0**	**$ 2,060.8**

(A) The Company recognized a cumulative effect adjustment for its uncertain tax positions on January 1, 2007 related to the adoption of a new accounting principle.

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 *(In millions)*	**2009**	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 261.1**	$ 237.4	$ 245.2
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation and amortization	**262.6**	217.5	195.3
Impairment of assets	**3.1**	0.4	0.5
Deferred income taxes and investment tax credits, net	**269.8**	123.4	16.1
Allowance for equity funds used during construction	**(15.1)**	---	---
Loss on disposition and abandonment of assets	**1.3**	0.3	3.7
Write-down of regulatory assets	---	9.2	---
Stock-based compensation expense	**5.8**	4.3	3.6
Excess tax benefit on stock-based compensation	**(3.3)**	(1.9)	(2.8)
Stock-based compensation converted to cash for tax withholding	**(1.7)**	---	---
Price risk management assets	**27.8**	(25.9)	32.0
Price risk management liabilities	**(88.7)**	126.9	(74.3)
Other assets	**15.4**	5.1	(24.8)
Other liabilities	**(55.2)**	(22.9)	(61.5)
Change in certain current assets and liabilities			
Funds on deposit	---	---	32.0
Accounts receivable, net	**(3.3)**	46.3	9.9
Accrued unbilled revenues	**(10.2)**	(1.3)	(6.0)
Income taxes receivable	**(157.7)**	---	---
Fuel, materials and supplies inventories	**(36.1)**	(15.2)	(21.3)
Gas imbalance assets	**3.0**	0.5	(3.9)
Fuel clause under recoveries	**23.7**	3.3	(27.3)
Other current assets	**(1.4)**	(2.2)	5.4
Accounts payable	**(17.2)**	(119.6)	104.3
Customer deposits	**6.6**	3.3	2.1
Accrued taxes	**11.2**	(9.0)	(13.5)
Accrued interest	**11.9**	11.7	(7.0)
Accrued compensation	**4.9**	(8.7)	7.9
Gas imbalance liabilities	**(12.9)**	13.8	---
Fuel clause over recoveries	**178.9**	4.4	(92.1)
Other current liabilities	**(29.8)**	23.9	5.0
Net Cash Provided from Operating Activities	**654.5**	625.0	328.5
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(847.8)**	(1,184.5)	(557.7)
Construction reimbursement	**38.8**	---	---
Proceeds from sale of assets	**1.4**	0.8	1.4
Capital contribution to unconsolidated affiliate	**(0.9)**	(0.3)	---
Other investing activities	---	(0.1)	---
Net Cash Used in Investing Activities	**(808.5)**	(1,184.1)	(556.3)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	**444.8**	743.0	---
Proceeds from line of credit	**80.0**	145.0	---
Issuance of common stock	**79.6**	36.4	8.2
Excess tax benefit on stock-based compensation	**3.3**	1.9	2.8
Contributions from noncontrolling interest partner	---	0.5	9.7
Retirement of long-term debt	**(110.8)**	(51.1)	(3.1)
(Decrease) increase in short-term debt, net	**(123.0)**	2.2	295.8
Dividends paid on common stock	**(136.2)**	(128.2)	(124.7)
Repayment of line of credit	**(200.0)**	(25.0)	---
Net Cash Provided from Financing Activities	**37.7**	724.7	188.7
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(116.3)**	165.6	(39.1)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**174.4**	8.8	47.9
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 58.1**	$ 174.4	$ 8.8

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

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 rate 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 gas business in 1928 and is no longer engaged in the gas distribution business.

Enogex LLC and its subsidiaries ("Enogex") are providers of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. Prior to January 1, 2008, Enogex owned OGE Energy Resources, Inc. ("OERI"), whose primary operations are in natural gas marketing. On January 1, 2008, Enogex distributed the stock of OERI to OGE Energy. Enogex's historical consolidated financial statements were prepared from Enogex's books and records related to Enogex's operating assets. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream, LLC joint venture ("Atoka") through Enogex Atoka LLC, a wholly-owned subsidiary of Enogex Gathering & Processing LLC. The Company has consolidated 100 percent of Atoka in its consolidated financial statements as Enogex acts as the managing member of Atoka and has control over the operations of Atoka with a separate presentation for the noncontrolling interest. Enogex is a Delaware single-member limited liability company. Effective July 1, 2009, Enogex LLC formed a new entity, Enogex Gathering & Processing LLC, a wholly-owned subsidiary of Enogex, for purposes of holding the membership interests of Enogex Gas Gathering LLC, Enogex Products LLC ("Products") and Enogex Atoka LLC, which were previously direct wholly-owned subsidiaries of Enogex LLC.

In July 2008, OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture, conducting business as Tallgrass Transmission L.L.C. ("Tallgrass"), to construct high-capacity transmission line projects. The Company owns 50 percent of Tallgrass. Tallgrass is intended to allow the participating companies to lead development of renewable wind by sharing capital costs associated with transmission construction.

The Company charges operating costs to its subsidiaries based on several factors. Operating costs directly related to specific subsidiaries are assigned to those subsidiaries. Where more than one subsidiary benefits from certain expenditures, the costs are shared between those subsidiaries receiving the benefits. Operating costs incurred for the benefit of all subsidiaries are allocated among the subsidiaries, based primarily upon head-count, occupancy, usage or the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. The Company adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. The Company believes this method provides a reasonable basis for allocating common expenses.

Basis of Presentation

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at December 31, 2009 and 2008, the results of its operations and the results of its cash flows for the years ended December 31, 2009, 2008 and 2007, have been included and are of a normal recurring nature except as otherwise disclosed. Management also has evaluated the impact of subsequent events for inclusion in the Company's Consolidated Financial Statements occurring after December 31, 2009 through February 17, 2010, the date the Company's financial statements were issued, and, in the opinion of management, the Company's Consolidated Financial Statements and Notes contain all necessary adjustments and disclosures resulting from that evaluation.

Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

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

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

December 31 *(In millions)*		**2009**		2008
Regulatory Assets				
Benefit obligations regulatory asset	**$**	**357.8**	$	344.7
Deferred storm expenses		**28.0**		32.2
Income taxes recoverable from customers, net		**19.1**		14.6
Deferred pension plan expenses		**18.1**		14.6
Unamortized loss on reacquired debt		**16.5**		17.7
Red Rock deferred expenses		**7.7**		7.4
Fuel clause under recoveries		**0.3**		24.0
McClain Plant deferred expenses		**---**		6.2
Miscellaneous		**3.9**		2.9
Total Regulatory Assets	**$**	**451.4**	$	464.3
Regulatory Liabilities				
Fuel clause over recoveries	**$**	**187.5**	$	8.6
Accrued removal obligations, net		**168.2**		150.9
Miscellaneous		**7.3**		4.9
Total Regulatory Liabilities	**$**	**363.0**	$	164.4

The benefit obligations regulatory asset is comprised of items which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost including, net loss, prior service cost and net transition obligation. For companies not subject to accounting principles for certain types of rate-regulated activities, these charges were required to be included in Accumulated Other Comprehensive Income. However, for companies subject to accounting principles for certain types of rate-regulated activities, these charges were allowed to be recorded as a regulatory asset if: (i) the utility had historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates and (ii) there was no negative evidence that the existing regulatory treatment will change. OG&E met both criteria and, therefore, recorded the net loss, prior service cost and net transition obligation as a regulatory asset as these expenses are probable of future recovery. If, in the future, the regulatory bodies indicate a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the benefit obligations regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

The following table is a summary of the components of the benefit obligations regulatory asset at:

December 31 *(In millions)*		**2009**		2008
Defined benefit pension plan and restoration of retirement income plan:				
Net loss	**$**	**222.8**	$	259.8
Prior service cost		**12.5**		3.5
Defined benefit postretirement plans:				
Net loss		**114.9**		70.4
Net transition obligation		**7.6**		10.2
Prior service cost		**---**		0.8
Total	**$**	**357.8**	$	344.7

The following amounts in the benefit obligations regulatory asset at December 31, 2009 are expected to be recognized as components of net periodic benefit cost in 2010:

(In millions)		
Defined benefit pension plan and restoration of retirement income plan:		
Net loss	**$**	**15.9**
Prior service cost		**2.7**
Defined benefit postretirement plans:		
Net loss		**9.1**
Net transition obligation		**2.5**
Total	**$**	**30.2**

In accordance with the September 2008 OCC rate order, OG&E was allowed to defer the Oklahoma storm-related operation and maintenance expenses in excess of $2.7 million and will reserve for any Oklahoma storm-related expenses less than $2.7 million. OG&E will recover the deferred amounts over a five-year period ending in August 2013.

Income taxes recoverable from customers, which represents income tax benefits previously used to reduce OG&E's revenues, are treated as regulatory assets and liabilities and are being amortized over the estimated remaining life of the assets to which they relate. These amounts are being recovered in rates as the temporary differences that generated the income tax benefit turn around. The income tax related regulatory assets and liabilities are netted on the Company's Consolidated Balance Sheets in the line item, "Income Taxes Recoverable from Customers, Net."

In accordance with the OCC order received by OG&E in December 2005 in its Oklahoma rate case, OG&E was allowed to recover a certain amount of pension plan expenses. These deferred amounts have been recorded as a regulatory asset as OG&E received an order in July 2009 allowing it to begin recovery of approximately $16.8 million of these costs over a four-year period. In accordance with the APSC order received by OG&E in May 2009 in its Arkansas rate case, OG&E was allowed recovery of its 2006 and 2007 pension settlement costs. During the second quarter of 2009, OG&E reduced its pension expense and recorded a regulatory asset for approximately $3.2 million, which will be amortized over approximately a 10-year period, as allowed in the Arkansas rate order. Both the Oklahoma and Arkansas pension plan expenses are reflected in Deferred Pension Plan Expenses in the table above.

Unamortized loss on reacquired debt is comprised of unamortized debt issuance costs related to the early retirement of OG&E's long-term debt. These amounts are being amortized over the term of the long-term debt which replaced the previous long-term debt. The unamortized loss on reacquired debt is not included in OG&E's rate base and does not otherwise earn a rate of return.

Fuel clause under recoveries are generated from under recoveries from OG&E's customers when OG&E's cost of fuel exceeds the amount billed to its customers. Fuel clause over recoveries are generated from over recoveries from OG&E's customers when the amount billed to its customers exceeds OG&E's cost of fuel. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances. As part of the OCC order in OG&E's Oklahoma rate case, OG&E will refund approximately $80.4 million in fuel clause over recoveries to its Oklahoma customers over the next seven months.

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations.

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If the Company were required to discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets; the financial effects of which could be significant.

Use of Estimates

In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, impairment estimates, contingency reserves, asset retirement obligations ("ARO"), fair value and cash flow hedges, regulatory assets and liabilities, unbilled revenues for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable and the valuation of OERI's purchase and sale contracts.

Cash and Cash Equivalents

For purposes of the Consolidated Financial Statements, the Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates fair value.

Allowance for Uncollectible Accounts Receivable

For OG&E, customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. Beginning in August 2009 and going forward, there was a change in the provision calculation as a result of the Oklahoma rate case whereby the portion of the uncollectible provision related to fuel will be recovered through the fuel adjustment clause. The allowance for uncollectible accounts receivable for Enogex and OERI are calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when Enogex believes the collection of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was approximately $2.4 million and $3.2 million at December 31, 2009 and 2008, respectively.

For OG&E, new business customers are required to provide a security deposit in the form of cash, 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, the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty and the monitoring of the financial position of existing counterparties on an ongoing basis.

Fuel Inventories

OG&E

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. OG&E uses the weighted-average cost method of accounting for inventory that is physically added to or withdrawn from storage or stockpiles. The amount of fuel inventory was approximately $101.0 million and $56.6 million at December 31, 2009 and 2008, respectively.

Enogex

Natural gas inventory is held by Enogex and is valued using moving average cost. Enogex maintains natural gas inventory to provide operational support for its pipeline deliveries. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2009 and 2008, Enogex recorded write-downs to market value related to natural gas storage inventory of approximately $5.8 million and $0.7 million, respectively. Enogex did not record a write-down to market value related to natural gas storage inventory during 2007. The amount of Enogex's natural gas inventory was approximately $10.2 million and $16.2 million at December 31, 2009 and 2008, respectively. The cost of gas associated with sales of natural gas storage inventory is presented in Cost of Goods Sold on the Consolidated Statements of Income.

OERI

As part of its recurring buy and sell activity, OERI injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. In an effort to mitigate market price exposures, OERI enters into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by OERI is recorded at the lower of cost or market. During 2009, 2008 and 2007, OERI recorded write-downs to market value related to natural gas storage inventory of approximately $0.3 million, $6.2 million and $3.6 million, respectively. The amount of OERI's natural gas inventory was approximately $7.3 million and $15.9 million at December 31, 2009 and 2008, respectively. The cost of gas associated with sales of natural gas storage inventory is presented in Cost of Goods Sold on the Consolidated Statements of Income.

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by Enogex's pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or made up in-kind depending on contractual terms. Enogex values all imbalances at an average of current market indices applicable to Enogex's operations, not to exceed net realizable value.

Property, Plant and Equipment

OG&E

All property, plant and equipment is recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and the allowance for funds used during construction ("AFUDC"). Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and the cost of such property is charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance is recorded as a loss in the Consolidated Statements of Income as Other Expense. Repair and replacement of minor items of property are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense.

The below tables present OG&E's ownership interest in the jointly-owned 520 megawatt ("MW") natural gas-fired combined cycle NRG McClain Station ("McClain Plant") and the jointly-owned 1,230 MW natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma ("Redbud Facility"), and, as disclosed below, only OG&E's ownership interest is reflected in the property, plant and equipment and accumulated depreciation balances in these tables. The owners of the remaining interests in the McClain Plant and the Redbud Facility are responsible for providing their own financing of capital expenditures. Also, only OG&E's proportionate interests of any direct expenses of the McClain Plant and the Redbud Facility such as fuel, maintenance expense and other operating expenses are included in the applicable financial statements captions in the Consolidated Statements of Income.

December 31, 2009 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant	**77**	**$ 197.7**	**$ 55.3**	**$ 142.4**
Redbud Facility	**51**	**$ 523.3(A)**	**$ 80.3(B)**	**$ 443.0**

(A) This amount includes a plant acquisition adjustment of approximately $148.3 million.
(B) This amount includes accumulated amortization of the plant acquisition adjustment of approximately $6.9 million.

December 31, 2008 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant	77	$ 181.0	$ 44.6	$ 136.4
Redbud Facility	51	$ 496.6(C)	$ 63.9(D)	$ 432.7

(C) This amount includes a plant acquisition adjustment of approximately $153.7 million.
(D) This amount includes accumulated amortization of the plant acquisition adjustment of approximately $1.5 million.

Enogex

All property, plant and equipment is recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and capitalized interest. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance is recorded as a loss in the Consolidated Statements of Income as Other Expense. Repair and removal costs are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense.

OGE Energy Consolidated

The Company's property, plant and equipment and related accumulated depreciation are divided into the following major classes at:

December 31, 2009 ***(In millions)***	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company and OERI)			
Holding company property, plant and equipment	**$ 107.4**	**$ 75.8**	**$ 31.6**
OERI property, plant and equipment	**7.3**	**7.0**	**0.3**
OGE Energy property, plant and equipment	**114.7**	**82.8**	**31.9**
OG&E			
Distribution assets	**2,676.2**	**861.1**	**1,815.1**
Electric generation assets	**2,878.2**	**1,141.5**	**1,736.7**
Transmission assets	**1,071.6**	**310.1**	**761.5**
Intangible plant	**29.7**	**22.6**	**7.1**
Other property and equipment	**227.9**	**80.7**	**147.2**
OG&E property, plant and equipment	**6,883.6**	**2,416.0**	**4,467.6**
Enogex			
Transportation and storage assets	**873.1**	**228.8**	**644.3**
Gathering and processing assets	**1,081.8**	**314.0**	**767.8**
Enogex property, plant and equipment	**1,954.9**	**542.8**	**1,412.1**
Total property, plant and equipment	**$ 8,953.2**	**$ 3,041.6**	**$ 5,911.6**

December 31, 2008 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company and OERI)			
Holding company property, plant and equipment	$ 101.4	$ 68.8	$ 32.6
OERI property, plant and equipment	7.3	7.0	0.3
OGE Energy property, plant and equipment	108.7	75.8	32.9
OG&E			
Distribution assets	2,551.5	824.8	1,726.7
Electric generation assets	2,623.8	1,095.4	1,528.4
Transmission assets	846.1	299.8	546.3
Intangible plant	26.8	18.4	8.4
Other property and equipment	222.0	76.3	145.7
OG&E property, plant and equipment	6,270.2	2,314.7	3,955.5
Enogex			
Transportation and storage assets	822.0	208.6	613.4
Gathering and processing assets	920.5	272.5	648.0
Enogex property, plant and equipment	1,742.5	481.1	1,261.4
Total property, plant and equipment	$ 8,121.4	$ 2,871.6	$ 5,249.8

Depreciation and Amortization

OG&E

The provision for depreciation, which was approximately 2.9 percent and 2.7 percent, respectively, of the average depreciable utility plant for 2009 and 2008, is provided on a straight-line method over the estimated service life of the utility assets. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant, and is based on the average life group method. In 2010, the provision for depreciation is projected to be approximately 2.9 percent of the average depreciable utility plant. Amortization of intangibles is computed using the straight-line method. Approximately 71.4 percent of the remaining amortizable intangible plant balance at December 31, 2009 will be amortized over three years with approximately 28.6 percent of the remaining amortizable intangible plant balance at December 31, 2009 being amortized over their respective lives ranging from four to 25 years. Amortization of plant acquisition adjustments is provided on a straight-line basis over the estimated remaining service life of the acquired asset. Plant acquisition adjustments include approximately $148.3 million for the Redbud Facility, which are being amortized over a 27-year life and approximately $3.1 million for certain substation facilities in OG&E's service territory, which are being amortized over a 26 to 59-year period.

Enogex

Depreciation is computed principally on the straight-line method using estimated useful lives of three to 83 years for transportation and storage assets and three to 30 years for gathering and processing assets. Amortization of intangibles other than debt costs is computed using the straight-line method over the respective lives of the intangibles ranging up to 20 years.

Asset Retirement Obligations

In the fourth quarter of 2009, OG&E recorded an ARO for approximately $4.5 million related to its OU Spirit wind project in western Oklahoma ("OU Spirit"). Beginning January 1, 2010, OG&E will amortize the remaining value of the related ARO asset over the estimated remaining life of 35 years. The Company also has other previously recorded AROs that are being amortized over their respective lives ranging from 20 to 99 years. The Company also has certain AROs that have not been recorded because the Company determined that these assets, primarily related to Enogex's processing plants and compression sites and OG&E's power plant sites, have indefinite lives.

Impairment of Assets

The Company assesses potential impairments of assets or asset groups when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset or asset group. For purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Estimates of future cash flows used to test the recoverability of a long-lived asset or asset group shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset or asset group. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. The Company recorded impairments of approximately $3.1 million, $0.4 million and $0.5 million in 2009, 2008 and 2007, respectively.

Allowance for Funds Used During Construction

For OG&E, AFUDC is calculated according to the FERC pronouncements for the imputed cost of equity and borrowed funds. AFUDC, a non-cash item, is reflected as a credit in the Consolidated Statements of Income and as a charge to Construction Work in Progress in the Consolidated Balance Sheets. AFUDC rates, compounded semi-annually, were 7.99 percent, 3.58 percent and 5.78 percent for the years 2009, 2008 and 2007, respectively. The increase in the AFUDC rates in 2009 was primarily due to the lack of short-term borrowings in conjunction with a high level of capital spending.

Collection of Sales Tax

In the course of its operations, OG&E collects sales tax from its customers. OG&E records a current liability from sales taxes when it bills its customers and eliminates this liability when the taxes are remitted to the appropriate governmental authorities. OG&E excludes the sales tax collected from its operating revenues.

Revenue Recognition

OG&E

General

OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

SPP Purchases and Sales

OG&E participates in the Southwest Power Pool ("SPP") energy imbalance service market in a dual role as a load serving entity and as a generation owner. The energy imbalance service market requires cash settlements for over or under schedules of generation and load. Market participants, including OG&E, are required to submit resource plans and can submit offer curves for each resource available for dispatch. A function of interchange accounting is to match participants' megawatt-hour ("MWH") entitlements (generation plus scheduled bilateral purchases) against their MWH obligations (load plus scheduled bilateral sales) during every hour of every day. If the net result during any given hour is an entitlement, the participant is credited with a spot-market sale to the SPP at the respective market price for that hour; if the net result is an obligation, the participant is charged with a spot-market purchase from the SPP at the respective market price for that hour. The SPP purchases and sales are not allocated to individual customers. OG&E records the hourly sales to the SPP at market rates in Operating Revenues and the hourly purchases from the SPP at market rates in Cost of Goods Sold in its Consolidated Financial Statements.

Enogex

Operating revenues for gathering, processing, transportation and storage services for Enogex are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Operating revenues associated with the production of natural gas liquids ("NGLs") are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated operating revenues are reflected in Accounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income. Enogex's key natural gas producer customers in 2009 included Chesapeake Energy Marketing Inc., Devon Gas Services, L.P., Apache Corporation, BP America Production Company and Samson Resources Company. During 2009, these five customers accounted for approximately 18.6 percent, 13.2 percent, 12.7 percent, 4.0 percent and 3.9 percent, respectively, of Enogex's gathering and processing volumes.

During 2009, Enogex's top 10 natural gas producer customers accounted for approximately 66.6 percent of Enogex's gathering and processing volumes.

Enogex recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold.

Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

Management may designate certain derivative instruments for the purchase or sale of physical commodities as normal purchases and normal sales contracts. Normal purchases and normal sales contracts are not recorded in Price Risk Management ("PRM") assets or liabilities in the 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 and (ii) commodity contracts for the sale of NGLs produced by Enogex's gathering and processing business.

OERI

OERI engages in energy marketing, trading, risk management and hedging activities related to the purchase and sale of natural gas as well as hedging activity related to the sale of natural gas and NGLs on behalf of the Company. Contracts utilized in these activities generally include purchases and sales for physical delivery of natural gas, over-the-counter forward swap and option contracts and exchange traded futures and options. OERI's transactions that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as PRM assets or liabilities in the Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement, or against the brokerage deposits in Other Current Assets. The offsetting unrealized gains and losses from changes in the market value of open contracts are included in Operating Revenues in the Consolidated Statements of Income or in Other Comprehensive Income for derivatives designated and qualifying as cash flow hedges. Contracts resulting in delivery of a commodity are included as sales or purchases in the Consolidated Statements of Income as Operating Revenues or Cost of Goods Sold depending on whether the contract relates to the sale or purchase of the commodity.

Operating revenues for physical delivery of natural gas are recorded the month of physical delivery based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Estimated operating revenues are reflected in Accounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income.

Fuel Adjustment Clauses

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component in the cost-of-service for ratemaking, are passed through to OG&E's customers through fuel adjustment clauses, which are subject to periodic review by the OCC, the APSC and the FERC.

Accrued Vacation

The Company accrues vacation pay by establishing a liability for vacation earned during the current year, but not payable until the following year.

Accumulated Other Comprehensive Income (Loss)

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

December 31 *(In millions)*		**2009**		2008
Defined benefit pension plan and restoration of retirement income plan:				
Net loss, net of tax (($65.6) and ($71.6) pre-tax, respectively)	**$**	**(40.0)**	$	(43.8)
Prior service cost, net of tax (($1.1) and ($0.8) pre-tax, respectively)		**(0.7)**		(0.5)
Defined benefit postretirement plans:				
Net loss, net of tax (($21.2) and ($11.6) pre-tax, respectively)		**(10.7)**		(5.3)
Net transition obligation, net of tax (($0.6) and ($0.8) pre-tax, respectively)		**(0.4)**		(0.5)
Prior service cost, net of tax (($0.1) and ($0.3) pre-tax, respectively)		---		(0.2)
Deferred hedging gains (losses), net of tax (($35.5) and $62.4 pre-tax, respectively)		**(21.7)**		38.1
Deferred hedging losses on interest rate swaps, net of tax (($1.9) and ($2.4) pre-tax, respectively)		**(1.2)**		(1.5)
Total accumulated other comprehensive loss, net of tax	**$**	**(74.7)**	$	(13.7)

Approximately $24.4 million of the deferred hedging losses at December 31, 2009 are expected to be recognized into earnings during 2010. At both December 31, 2009 and 2008, there was no accumulated other comprehensive income related to Enogex's noncontrolling interest in Atoka.

Defined Benefit Pension and Restoration of Retirement Income and Postretirement Plans

The Company is required to disclose the amounts in accumulated other comprehensive loss at December 31, 2009 that are expected to be recognized as components of net periodic benefit cost in 2010 which are as follows:

(In millions)		
Defined benefit pension plan and restoration of retirement income plan:		
Net loss, net of tax ($4.7 pre-tax)	**$**	**2.9**
Prior service cost, net of tax ($0.4 pre-tax)		**0.2**
Defined benefit postretirement plans:		
Net loss, net of tax ($1.9 pre-tax)		**1.2**
Net transition obligation, net of tax ($0.2 pre-tax)		**0.1**
Total	**$**	**4.4**

Environmental Costs

Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense or deferred as a regulatory asset based on expected recovery from customers in future rates, if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where OG&E or Enogex have been designated as one of several potentially responsible parties, the amount accrued represents OG&E's or Enogex's estimated share of the cost. The Company has less than $0.1 million in accrued environmental liabilities at both December 31, 2009 and 2008.

Reclassifications

Certain prior year amounts have been reclassified on the Consolidated Financial Statements to conform to the 2009 presentation related to the separate presentation of the noncontrolling interest in Atoka in connection with the Company's adoption of standards related to the accounting for noncontrolling interests in consolidated financial statements on January 1, 2009, which revised the relevance, comparability and transparency of an entity's financial information by establishing standards for the accounting and reporting for a noncontrolling interest in a subsidiary.

2. Accounting Pronouncements

In December 2008, the Financial Accounting Standards Board ("FASB") issued "Employer's Disclosures about Postretirement Benefit Plan Assets," which amends previously issued accounting guidance in this area. The new standard applies to employers with defined benefit pension or other postretirement benefit plans. The new standard requires additional disclosures related to: (i) investment policies and strategies, (ii) categories of plan assets, (iii) fair value measurement of plan assets and (iv) significant concentrations of risk. The new standard is effective for fiscal years ending after December 15, 2009, with earlier application permitted. Upon initial application, prior periods are not required to be presented for comparative purposes. The Company adopted this new standard effective December 31, 2009 and has presented the additional disclosures in Note 11.

In December 2009, the FASB issued "Consolidations – Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities," which amends previously issued accounting guidance in this area. The new standard applies to entities involved with variable interest entities ("VIE"). The new standard changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. The determination of whether a reporting entity is required to consolidate another entity is based on, among other things, the other entity's purpose and design and the reporting entity's ability to direct the activities of the other entity that most significantly impact the other entity's economic performance. The new standard requires additional disclosures related to: (i) an entity's involvement with VIE's and (ii) any significant changes in risk exposure due to that involvement. The new standard is effective for fiscal years beginning after November 15, 2009, and interim periods following initial adoption, with earlier application prohibited. Upon initial application, prior periods are not required to be presented for comparative purposes. The Company adopted this new standard effective January 1, 2010. The adoption of this new standard did not have a material impact on the Company's consolidated financial position or results of operations.

In January 2010, the FASB issued "Fair Value Measurements and Disclosures: Improving Disclosures about Fair Value Measurements," which requires new disclosures and clarifies existing disclosure requirements about fair value measurement as set forth in previously issued accounting guidance in this area. The new standard requires additional disclosures related to: (i) the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and the reasons for the transfers and (ii) presenting separate information about purchases, sales, issuances and settlements (on a gross basis) in the reconciliation for fair value measurements using significant unobservable inputs (Level 3). Also, the new standard clarifies the requirements of previously issued accounting guidance in this area related to: (i) a reporting entity's need to use judgment in determining the appropriate classes of assets and liabilities and (ii) a reporting entity's disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements. The new standard is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the rollforward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. Early application is permitted. The Company adopted this new standard effective January 1, 2010 and will include the required disclosures in the Company's Form 10-Q for the quarter ended March 31, 2010.

3. Fair Value Measurements

The following tables are a summary of the Company's assets and liabilities that are measured at fair value on a recurring basis at December 31, 2009 and 2008.

(In millions)	**December 31, 2009**	**Level 1**	**Level 2**	**Level 3**
Assets				
Gross derivative assets	**$ 71.3**	**$ 16.1**	**$ 6.2**	**$ 49.0**
Gas imbalance assets	**3.2**	**---**	**3.2**	**---**
Total	**$ 74.5**	**$ 16.1**	**$ 9.4**	**$ 49.0**
Liabilities				
Gross derivative liabilities	**$ 77.8**	**$ 13.3**	**$ 49.8**	**$ 14.7**
Gas imbalance liabilities (A)	**8.0**	**---**	**8.0**	**---**
Total	**$ 85.8**	**$ 13.3**	**$ 57.8**	**$ 14.7**

(A) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of approximately $4.0 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.

(In millions)	December 31, 2008	Level 1	Level 2	Level 3
Assets				
Gross derivative assets	$ 243.7	$ 83.9	$ 38.6	$ 121.2
Gas imbalance assets	6.2	---	6.2	---
Total	$ 249.9	$ 83.9	$ 44.8	$ 121.2
Liabilities				
Gross derivative liabilities	$ 141.8	$ 67.7	$ 74.1	$ ---
Gas imbalance liabilities (B)	13.1	---	13.1	---
Total	$ 154.9	$ 67.7	$ 87.2	$ ---

(B) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of approximately $11.8 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.

In the fourth quarter of 2009, OG&E recorded an ARO for approximately $4.5 million related to OU Spirit, which is measured at fair value on a nonrecurring basis and is considered level 3 in the fair value hierarchy. The inputs used in the valuation of the ARO include the term of the OU Spirit lease agreement, the average inflation rate, market risk premium and the credit-adjusted risk free interest rate. The term of the ARO of 35 years was determined by the OU Spirit lease agreement which states that OG&E will remove the wind turbines and related facilities at the time the lease expires. The inflation rate is calculated as an average of multiple sources including the Gross Domestic Product, Consumer Price Index, etc. The market risk premium is calculated using the U.S. treasury strip rate. The credit-adjusted risk free interest rate is calculated as the market risk premium plus 120 basis points.

The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. An example of instruments that may be classified as Level 1 includes futures transactions for energy commodities traded on the New York Mercantile Exchange (“NYMEX”).

Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs include the following: (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in markets that are not active, (iii) inputs other than quoted prices that are observable for the asset or liability or (iv) inputs that are derived principally from or corroborated by observable market data by correlation or other means. An example of instruments that may be classified as Level 2 includes energy commodity purchase or sales transactions in a market such that the pricing is closely related to the NYMEX pricing.

Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that observable inputs are not available. Unobservable inputs shall reflect the reporting entity’s own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk). Unobservable inputs shall be developed based on the best information available in the circumstances, which might include the reporting entity’s own data. The reporting entity’s own data used to develop unobservable inputs shall be adjusted if information is reasonably available that indicates that market participants would use different assumptions. Examples of instruments that may be classified as Level 3 include energy commodity purchase or sales transactions of a longer duration or in an inactive market or the valuation of ARO’s 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 Consolidated Balance Sheet at:

December 31 *(In millions)*		**2009**		2008
Assets				
Gross derivative assets	**$**	**71.3**	$	243.7
Less: Amounts held in clearing broker accounts reflected in Other Current Assets		**17.3**		86.3
Less: Amounts offset under master netting agreements		**47.9**		65.4
Less: Net collateral payments received from counterparties		---		58.1
Net Price Risk Management Assets	**$**	**6.1**	$	33.9
Liabilities				
Gross derivative liabilities	**$**	**77.8**	$	141.8
Less: Amounts held in clearing broker accounts reflected in Other Current Assets		**15.6**		70.3
Less: Amounts offset under master netting agreements		**47.9**		65.4
Net Price Risk Management Liabilities	**$**	**14.3**	$	6.1

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

	Derivative Assets			
Year Ended December 31 *(In millions)*		**2009**		2008
Balance at January 1	**$**	**121.2**	$	1.4
Total gains or losses (realized/unrealized)				
Included in earnings		---		---
Included in other comprehensive income		**(54.0)**		2.4
Purchases, sales, issuances and settlements, net (A)		**(18.2)**		82.0
Transfers in and/or out of Level 3 (B)		---		35.4
Balance at December 31	**$**	**49.0**	$	121.2
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 December 31	**$**	---	$	---

(A) During 2008, Enogex purchased NGLs options to hedge a portion of the commodity price risk associated with its keep-whole and percent-of-liquids processing arrangements for 2011 and to reset the price level of a portion of the existing hedged volumes for 2010.

(B) During 2008, the transfers into Level 3 were primarily due to NGLs swaps and shorter-term NGLs options being recategorized as Level 3. These transactions were previously categorized as Level 2 based on corroboration to price data from a related, active market. The correlation between the markets deteriorated during the fourth quarter of 2008, resulting in the transactions being transferred to Level 3.

Year Ended December 31 *(In millions)*	Derivative Liabilities **2009**	2008
Balance at January 1	**$ ---**	$ ---
Total gains or losses (realized/unrealized)		
Included in earnings	**---**	---
Included in other comprehensive income	**14.7**	---
Purchases, sales, issuances and settlements, net	**---**	---
Transfers in and/or out of Level 3	**---**	---
Balance at December 31	**$ 14.7**	$ ---
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to liabilities held at December 31	**$ ---**	$ ---

Gains and losses (realized and unrealized) included in earnings for the years ended December 31, 2009 and 2008 attributable to the change in unrealized gains or losses relating to assets and liabilities held at December 31, 2009 and 2008 , if any, are reported in Operating Revenues.

The following table is a summary of the fair value and carrying amount of the Company's financial instruments, including derivative contracts related to the Company's PRM activities, at:

December 31 *(In millions)*	**2009** Carrying Amount	**2009** Fair Value	2008 Carrying Amount	2008 Fair Value
Price Risk Management Assets				
Energy Derivative Contracts	**$ 6.1**	**$ 6.1**	$ 33.9	$ 33.9
Price Risk Management Liabilities				
Energy Derivative Contracts	**$ 14.3**	**$ 14.3**	$ 6.1	$ 6.1
Long-Term Debt				
OG&E Senior Notes	**$ 1,406.4**	**$ 1,492.1**	$ 1,406.1	$ 1,327.4
OGE Energy Senior Notes	**99.5**	**102.6**	99.5	93.4
OG&E Industrial Authority Bonds	**135.4**	**135.4**	135.3	135.3
Enogex Senior Notes	**736.8**	**746.7**	400.9	436.1
Enogex Revolving Credit Agreement	**---**	**---**	120.0	120.0

The carrying value of the financial instruments on the 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. 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 $5.8 million pre-tax ($3.6 million after tax, or $0.04 per basic and diluted share), $4.3 million pre-tax ($2.7 million after tax, or $0.03 per basic and diluted share) and $3.8 million pre-tax ($2.3 million after tax, or $0.03 per basic and diluted share) in 2009, 2008 and 2007, respectively, related to the Company's share-based payments. Also, during 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, which were settled in the Company's common stock.

The Company issues new shares to satisfy stock option exercises and payouts of earned performance units. In 2009, 2008 and 2007, there were 324,651 shares, 875,434 shares and 496,565 shares, respectively, of new common stock issued pursuant to the Company's Plans related to exercised stock options and payouts of earned performance units. The Company received approximately $3.5 million, $15.0 million and $8.2 million in 2009, 2008 and 2007, respectively, related to exercised stock options.

Performance Units

Under the Plans, the Company has issued performance units which represent the value of one share of the Company's common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the Plans). Each performance unit is subject to forfeiture if the recipient terminates employment with the Company or a subsidiary prior to the end of the award cycle (which, with the exception of one award of performance units to a new officer, is three years) for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant's number of full months of service during the award cycle, further adjusted based on the achievement of the performance goals during the award cycle.

The performance units granted based on total shareholder return ("TSR") are contingently awarded and will be payable in shares of the Company's common stock subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of an award cycle (*i.e*., three-year cliff vesting period, other than for one award which had a two-year cliff vesting period) is dependent on the Company's TSR ranking relative to a peer group of companies. The performance units granted based on earnings per share ("EPS") are contingently awarded and will be payable in shares of the Company's common stock based on the Company's EPS growth over an award cycle (*i.e*., three-year cliff vesting period, other than for one award which had a two-year cliff vesting period) compared to a target set at the time of the grant by the Compensation Committee of the Company's Board of Directors. All of the Company's performance units are classified as equity. If there is no or only a partial payout for the performance units at the end of the award cycle, the unearned performance units are cancelled. In 2009, 2008 and 2007, the Company awarded 422,017, 242,503 and 162,730 performance units, respectively, to certain employees of the Company and its subsidiaries.

Performance Units – Total Shareholder Return

The Company recorded compensation expense of approximately $4.4 million pre-tax ($2.7 million after tax), $3.2 million pre-tax ($2.0 million after tax) and $2.3 million pre-tax ($1.4 million after tax) in 2009, 2008 and 2007, respectively, related to the performance units based on TSR. The fair value of the performance units based on TSR was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units is a fixed amount determined at the grant date fair value and is recognized over the award cycle (typically, three years) regardless of whether performance units are awarded at the end of the award cycle. Dividends are not accrued or paid during the performance period and, therefore, are not included in the fair value calculation. Expected price volatility is based on the historical volatility of the Company's common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the award cycle. There are no post-vesting restrictions related to the Company's performance units based on TSR. The fair value of the performance units based on TSR was calculated based on the following assumptions at the grant date.

	2009	2008	2007
Expected dividend yield	4.5%	3.8%	3.6%
Expected price volatility	31.0%	18.7%	15.9%
Risk-free interest rate	1.25%	2.21%	4.47%
Expected life of units (in years)	2.88	2.84	2.95
Fair value of units granted	$ 25.55	$ 33.62	$ 24.18

A summary of the activity for the Company's performance units based on TSR at December 31, 2009 and changes during 2009 are summarized in the following table. Following the end of the performance period, payout of the performance units based on TSR is determined by the Company's TSR for such period compared to a peer group and payout requires the approval of the Compensation Committee of the Company's Board of Directors. Payouts, if any, are all made in common stock and are considered made when the payout is approved by the Compensation Committee.

(dollars in millions)	Number of Units	Stock Conversion Ratio (A)	Aggregate Intrinsic Value
Units Outstanding at 12/31/08	376,616	1:1	
Granted (B)	316,513	1:1	
Converted	(128,755)	1:1	$ 3.0
Forfeited	(17,907)	1:1	
Units Outstanding at 12/31/09	546,467	1:1	$ 36.3
Units Fully Vested at 12/31/09	78,997	1:1	$ 4.1

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

A summary of the activity for the Company's non-vested performance units based on TSR at December 31, 2009 and changes during 2009 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/08	247,861	$ 30.50
Granted (C)	316,513	$ 25.55
Vested	(78,997)	$ 24.18
Forfeited	(17,907)	$ 27.87
Units Non-Vested at 12/31/09 (D)	467,470	$ 28.27

(C) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.
(D) Of the 467,470 performance units not vested at December 31, 2009, 405,987 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2009, there was approximately $6.1 million in unrecognized compensation cost related to non-vested performance units based on TSR which is expected to be recognized over a weighted-average period of 1.72 years.

Performance Units – Earnings Per Share

The Company recorded compensation expense of approximately $1.4 million pre-tax ($0.8 million after tax), $1.2 million pre-tax ($0.7 million after tax) and $1.5 million pre-tax ($0.9 million after tax) in 2009, 2008 and 2007, respectively, related to the performance units based on EPS. The fair value of the performance units based on EPS is based on grant date fair value which is equivalent to the price of one share of the Company's common stock on the date of grant. The fair value of performance units based on EPS varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. The Company reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to the Company's performance units based on EPS. The grant date fair value of the 2007, 2008 and 2009 performance units was $33.59, $29.22 and $20.02, respectively.

A summary of the activity for the Company's performance units based on EPS at December 31, 2009 and changes during 2009 are summarized in the following table. Following the end of the performance period (typically, three years), payout of the performance units based on EPS growth is determined by the Company's growth in EPS for such period compared to a target set at the beginning of the period by the Compensation Committee of the Company's Board of Directors and payout requires the approval of the Compensation Committee. Payouts, if any, are all made in common stock and are considered made when approved by the Compensation Committee.

(dollars in millions)	Number of Units	Stock Conversion Ratio (A)	Aggregate Intrinsic Value
Units Outstanding at 12/31/08	125,464	1:1	
Granted (B)	105,504	1:1	
Converted	(42,914)	1:1	$ 2.4
Forfeited	(5,968)	1:1	
Units Outstanding at 12/31/09	182,086	1:1	$ 2.6
Units Fully Vested at 12/31/09	26,279	1:1	$ 0.7

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

A summary of the activity for the Company's non-vested performance units based on EPS at December 31, 2009 and changes during 2009 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/08	82,550	$ 30.66
Granted (C)	105,504	$ 20.02
Vested	(26,279)	$ 33.59
Forfeited	(5,968)	$ 25.17
Units Non-Vested at 12/31/09 (D)	155,807	$ 23.19

(C) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.
(D) Of the 155,807 performance units not vested at December 31, 2009, 135,312 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2009, there was approximately $1.5 million in unrecognized compensation cost related to non-vested performance units based on EPS which is expected to be recognized over a weighted-average period of 1.76 years.

Stock Options

The Company recorded no compensation expense in 2009, 2008 or 2007 related to stock options because at December 31, 2006, there was no unrecognized compensation cost related to non-vested options, which became fully vested in January 2007. A summary of the activity for the Company's stock options at December 31, 2009 and changes during 2009 are summarized in the following table:

(dollars in millions)	Number of Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
Options Outstanding at 12/31/08	425,247	$ 21.98		
Exercised	161,903	$ 21.32	$ 1.7	
Expired	16,600	$ 28.59	$ 0.5	
Options Outstanding at 12/31/09	246,744	$ 21.98	$ 3.7	2.87 years
Options Fully Vested and Exercisable at 12/31/09	246,744	$ 21.98	$ 3.7	2.87 years

Restricted Stock

Under the Plans and in 2008 and 2009, the Company issued restricted stock to certain existing non-officer employees as well as other executives upon hire to attract and retain individuals to be competitive in the marketplace. The restricted stock vests in one-third annual increments. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. These shares may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture. In 2009 and 2008, respectively, the Company awarded 6,226 shares and 56,798 shares of restricted stock. In 2009, there were 2,915 shares of restricted stock forfeited.

The Company recorded compensation expense of approximately $0.9 million pre-tax ($0.5 million after tax) and $0.3 million pre-tax ($0.2 million after tax) in 2009 and 2008, respectively, related to the restricted stock. The fair value of the restricted stock was based on the closing market price of the Company's common stock on the grant date. Compensation expense for the restricted stock is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a three-year vesting period. Also, the Company treats its restricted stock as multiple separate awards by recording compensation expense separately for each tranche whereby a substantial portion of the expense is recognized in the earlier years in the requisite service period. Dividends are accrued and paid during the vesting period and, therefore, are included in the fair value calculation. The expected life of the restricted stock is based on the non-vested period since inception of the three-year award cycle. There are no post-vesting restrictions related to the Company's restricted stock. The weighted-average grant date fair value of the 2009 and 2008 restricted stock was $33.38 and $30.84, respectively.

At December 31, 2009, there was approximately $0.7 million in unrecognized compensation cost related to non-vested restricted stock which is expected to be recognized over a weighted-average period of 2.00 years.

5. Derivative Instruments and Hedging Activities

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

Commodity Price Risk

The Company primarily uses forward physical contracts, commodity price swap contracts and commodity price option features to manage the Company's commodity price risk exposures. 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:

- NGLs 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 OERI's natural gas exposure associated with its storage and transportation contracts; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage OERI's marketing and trading activities.

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

The Company recognizes its non-exchange traded derivative instruments as PRM assets or liabilities in the 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 Consolidated Balance Sheets.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable debt, treasury lock agreements and commercial paper. 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. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce interest expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Credit Risk

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

Cash Flow Hedges

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

At December 31, 2009 and 2008, 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 long/short positions and operational storage natural gas, keep-whole natural gas and NGLs hedges. Enogex's cash flow hedging activity at December 31, 2009 covers the period from January 1, 2010 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 December 31, 2009 does not extend beyond the first quarter of 2010. At December 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	**0.5**	Current
Purchased Financial Options	NGLs	**1.3**	Current
Purchased Financial Options	NGLs	**1.3**	Non-Current
Total Purchased Financial Options		**2.6**	
Long Financial Swaps/Futures (fixed)	Natural Gas	**6.3**	Current
Long Financial Swaps/Futures (fixed)	Natural Gas	**5.2**	Non-Current
Total Long Financial Swaps/Futures (fixed)		**11.5**	
Short Financial Swaps/Futures (fixed)	Natural Gas	**4.0**	Current
Short Financial Basis Swaps	Natural Gas	**4.0**	Current

(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 December 31, 2009 and 2008, the Company had no outstanding commodity derivative instruments or treasury lock agreements that were designated as fair value hedges.

Derivatives Not Designated As Hedging Instruments

For derivative instruments that are not designated as either a cash flow or fair value hedge, the gain or loss on the derivative is recognized currently in earnings. Derivative instruments not designated as either a cash flow or a fair value hedge are utilized in OERI's asset management, marketing and trading activities. Derivative instruments not designated as either cash flow or fair value hedges also include contracts formerly designated as cash flow hedges of Enogex's NGLs, keep-whole natural gas and operational storage natural gas exposures. A portion of Enogex's processing agreements, which were previously under keep-whole arrangements, were converted to fee-based arrangements. As a result, effective June 30, 2009 Enogex de-designated a portion of these derivatives and entered into offsetting derivatives to close the positions. Also, effective November 12, 2009, in response to market opportunities, Enogex de-designated its operational storage hedges and entered into offsetting derivatives to close the positions.

At December 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)	
Short Financial Swaps/Futures (fixed)	NGLs	**0.8**	Current
Long Financial Swaps/Futures (fixed)	NGLs	**0.8**	Current
Physical Purchases (B)	Natural Gas	**16.1**	Current
Physical Purchases (B)	Natural Gas	**4.1**	Non-Current
Total Physical Purchases		**20.2**	
Physical Sales (B)	Natural Gas	**31.3**	Current
Physical Sales (B)	Natural Gas	**13.2**	Non-Current
Total Physical Sales		**44.5**	
Long Financial Swaps/Futures (fixed)	Natural Gas	**31.3**	Current
Long Financial Swaps/Futures (fixed)	Natural Gas	**1.0**	Non-Current
Total Long Financial Swaps/Futures (fixed)		**32.3**	
Short Financial Swaps/Futures (fixed)	Natural Gas	**31.8**	Current
Short Financial Swaps/Futures (fixed)	Natural Gas	**2.9**	Non-Current
Total Short Financial Swaps/Futures (fixed)		**34.7**	
Purchased Financial Option	Natural Gas	**9.5**	Current
Sold Financial Option	Natural Gas	**12.8**	Current
Long Financial Basis Swaps	Natural Gas	**7.7**	Current
Long Financial Basis Swaps	Natural Gas	**1.0**	Non-Current
Total Long Financial Basis Swaps		**8.7**	
Short Financial Basis Swaps	Natural Gas	**7.0**	Current
Short Financial Basis Swaps	Natural Gas	**1.2**	Non-Current
Total Short Financial Basis Swaps		**8.2**	

(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 Consolidated Balance Sheet at December 31, 2009 are as follows:

			Fair Value	
Instrument	**Commodity**	**Balance Sheet Location**	**Assets**	**Liabilities**
	(dollars in millions)			
Derivatives Designated as Hedging Instruments				
Financial Options	NGLs	Current PRM	$ **16.4**	$ ---
		Non-Current PRM	**23.4**	---
Financial Futures/Swaps	NGLs	Current PRM	---	**6.1**
Financial Futures/Swaps	Natural Gas	Current PRM	---	**14.8**
		Non-Current PRM	---	**19.7**
		Other Current Assets	**4.6**	**1.2**
Total Gross Derivatives Designated as Hedging Instruments			$ **44.4**	$ **41.8**

Derivatives Not Designated as Hedging Instruments

Financial Futures/Swaps (A)	NGLs	Current PRM	**$ 9.2**	**$ 8.6**
Financial Futures/Swaps (B)	Natural Gas	Current PRM	**3.6**	**12.3**
		Non-Current PRM	**---**	**0.1**
		Other Current Assets	**11.8**	**13.6**
Physical Purchases/Sales	Natural Gas	Current PRM	**0.8**	**0.6**
		Non-Current PRM	**0.6**	**---**
Financial Options	Natural Gas	Other Current Assets	**0.9**	**0.8**
Total Gross Derivatives Not Designated as Hedging Instruments			**$ 26.9**	**$ 36.0**
Total Gross Derivatives (C)			**$ 71.3**	**$ 77.8**

(A) The entire fair value of Financial Futures/Swaps – NGLs not designated as hedging instruments includes derivatives that were previously designated as hedging instruments and subsequently de-designated with offsetting derivatives to close the hedge positions.
(B) The fair value of Financial Futures/Swaps – Natural Gas not designated as hedging instruments includes derivatives that were previously designated as hedging instruments and subsequently de-designated with offsetting derivatives to close the hedge positions. The referenced derivatives had a fair value as presented in the table above in Current Assets of approximately $2.9 million and Current Liabilities of approximately $11.7 million.
(C) See reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2009 (see Note 3).

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Service ("Moody's") or Standard & Poor's were to lower the Company's senior unsecured debt rating to a below investment grade rating, at December 31, 2009, the Company would have been required to post approximately $11.8 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 December 31, 2009. In addition, the Company could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

The following table presents the effect of derivative instruments on the Company's Consolidated Statement of Income for the year ended December 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 Cash Flow Hedging Relationships					
NGLs Financial Options	**$ (56.4)**	Operating Revenues	**$ 1.7**	Operating Revenues	**$ ---**
NGLs Financial Futures/Swaps	**(33.7)**	Operating Revenues	**12.6**	Operating Revenues	**---**
Natural Gas Financial Futures/Swaps	**(19.8)**	Operating Revenues	**(26.5)**	Operating Revenues	**(0.2)**
Total	**$ (109.9)**	**Total**	**$ (12.2)**	**Total**	**$ (0.2)**

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at December 31, 2009 that is expected to be reclassified
into earnings within the next 12 months is a loss of approximately $24.4 million.

	Location of Gain or Loss Recognized in Income on Derivative	Amount of Gain or Loss Recognized in Income of Derivative
		(dollars in millions)
Derivatives Not Designated as Hedging Instruments		
Natural Gas Physical Purchases/Sales	Operating Revenues	**$ (24.3)**
Natural Gas Financial Futures/Swaps	Operating Revenues	**17.7**
NGLs Financial Futures/Swaps	Operating Revenues	**(0.2)**
Total		**$ (6.8)**

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Consolidated Balance Sheets. The Company has presented the fair values of its contracts under master netting agreements using a net fair value presentation.

6. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affect recognized assets and liabilities but which do not result in cash receipts or payments. Also disclosed in the table is cash paid for interest, net of interest capitalized, and cash paid for income taxes, net of income tax refunds.

Year ended December 31 *(In millions)*	**2009**	2008	2007
NON-CASH INVESTING AND FINANCING ACTIVITIES			
OU Spirit future installment payments to developer	**$ 3.9**	$ ---	$ ---
Power plant long-term service agreement	---	3.5	0.7
Capital lease for distribution equipment	---	0.3	---
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $14.7, $7.6, $4.9)	**$ 125.8**	$ 122.3	$ 93.5
Income taxes (net of income tax refunds)	**2.0**	---	86.6

7. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2009**	2008	2007
Provision (Benefit) for Current Income Taxes			
Federal	**$ (147.0)**	$ (18.6)	$ 96.0
State	**(3.1)**	(0.8)	3.9
Total Provision (Benefit) for Current Income Taxes	**(150.1)**	(19.4)	99.9
Provision for Deferred Income Taxes, net			
Federal	**259.5**	126.9	18.2
State	**5.3**	1.2	2.7
Total Provision for Deferred Income Taxes, net	**264.8**	128.1	20.9
Deferred Federal Investment Tax Credits, net	**(4.2)**	(4.6)	(4.8)
Income Taxes Relating to Other Income and Deductions	**10.6**	(2.9)	0.7
Total Income Tax Expense	**$ 121.1**	$ 101.2	$ 116.7

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal tax examinations by tax authorities for years prior to 2006 or state and local tax examinations by tax authorities for years prior to 2002. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. The Company continues to amortize its Federal investment tax credits on a ratable basis throughout the year. OG&E earns both Federal and Oklahoma state tax credits associated with the production from its 120 MW wind farm in northwestern Oklahoma ("Centennial") and its 101 MW OU Spirit wind farm in western Oklahoma. In addition, OG&E and Enogex earn Oklahoma state tax credits associated with their investments in electric generating and natural gas processing facilities which further reduce the Company's effective tax rate. The following schedule reconciles the statutory Federal tax rate to the effective income tax rate:

Year ended December 31	**2009**	2008	2007
Statutory Federal tax rate	**35.0 %**	35.0 %	35.0 %
State income taxes, net of Federal income tax benefit	**1.0**	0.2	1.9
Amortization of net unfunded deferred taxes	**0.7**	0.7	0.8
401(k) dividends	**(0.7)**	(0.8)	(1.2)
Medicare Part D subsidy	**(1.1)**	(0.3)	(0.3)
Federal investment tax credits, net	**(1.1)**	(1.4)	(1.3)
Federal renewable energy credit (A)	**(2.2)**	(2.7)	(2.0)
Other	**0.1**	(0.8)	(0.7)
Effective income tax rate as reported	**31.7 %**	29.9 %	32.2 %

(A) These are credits associated with the production from OG&E's wind farms.

OG&E filed a request with the Internal Revenue Service ("IRS") on December 29, 2008 for a change in its tax method of accounting related to the capitalization of repair expenditures. The accounting method change is for income tax purposes only and would allow the Company to record a cumulative tax deduction. For financial accounting purposes, the only change is recognition of the impact of the cash flow generated by accelerating income tax deductions. On December 10, 2009, OG&E received approval from the IRS for the change in accounting method. In December 2009, a claim for refund was filed to carry back the 2008 tax loss resulting in a tax refund of approximately $81.8 million, which OG&E received in February 2010. The expected refund was recorded in Income Taxes Receivable on the Consolidated Balance Sheet at December 31, 2009.

At December 31, 2009 and 2008, the Company had no material unrecognized tax benefits related to uncertain tax positions. The Company recognizes interest related to unrecognized tax benefits in interest expense and recognizes penalties in other expense.

The deferred tax provisions, set forth above, are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by OG&E. The components of Accumulated Deferred Taxes at December 31, 2009 and 2008, respectively, were as follows:

December 31 *(In millions)*		**2009**		2008
Current Accumulated Deferred Tax Assets				
Federal tax credits	**$**	**17.3**	$	9.2
Derivative instruments		**8.9**		---
Accrued vacation		**7.0**		7.2
Accrued liabilities		**4.7**		5.6
Uncollectible accounts		**0.9**		1.5
Other		**2.6**		---
Total Current Accumulated Deferred Tax Assets		**41.4**		23.5
Current Accumulated Deferred Tax Liabilities				
Derivative instruments		**---**		(7.0)
Other		**(1.6)**		(1.6)
Total Current Accumulated Deferred Tax Liabilities		**(1.6)**		(8.6)
Current Accumulated Deferred Tax Assets, net	**$**	**39.8**	$	14.9
Non-Current Accumulated Deferred Tax Liabilities				
Accelerated depreciation and other property related differences	**$**	**1,325.6**	$	1,025.7
Company pension plan		**51.3**		52.1
Income taxes refundable to customers, net		**7.4**		5.7
Bond redemption-unamortized costs		**5.2**		5.7
Regulatory asset		**0.2**		3.2
Derivative instruments		**---**		17.0
Total Non-Current Accumulated Deferred Tax Liabilities		**1,389.7**		1,109.4
Non-Current Accumulated Deferred Tax Assets				
Regulatory liabilities		**(51.1)**		(58.5)
Postretirement medical and life insurance benefits		**(52.5)**		(34.3)
State tax credits		**(29.9)**		(11.8)
Deferred Federal investment tax credits		**(5.1)**		(6.7)
Derivative instruments		**(3.4)**		---
Other		**(1.1)**		(1.2)
Total Non-Current Accumulated Deferred Tax Assets		**(143.1)**		(112.5)
Non-Current Accumulated Deferred Income Tax Liabilities, net	**$**	**1,246.6**	$	996.9

The Company currently estimates a Federal tax net operating loss for 2009 primarily caused by the accelerated tax depreciation provisions contained within the American Recovery and Reinvestment Act of 2009 ("ARRA"). ARRA allows a current deduction for 50 percent of the cost of certain property placed into service during 2009. This tax loss results in an approximate $76 million current income tax receivable related to the 2009 tax year. On November 6, 2009, the Worker, Homeownership, and Business Assistance Act of 2009 was signed into law by the President. This new law provides for a five-year carry back of net operating losses incurred in 2008 or 2009. This expanded carryback period will enable the Company to carry back the entire 2009 tax loss and obtain a tax refund of approximately $76 million, which the Company expects to receive during 2010.

The Company had a Federal renewable energy tax credit carryover from 2008 of approximately $9.2 million with an additional $8.1 million in credits being generated during 2009. In addition, the Company has an Oklahoma tax credit carryover from 2008 of approximately $18.1 million. During 2009, additional Oklahoma tax credits of approximately $30.4 million were generated or purchased by the Company. The Company currently believes that approximately $4.4 million of these state tax credit amounts will be utilized in the 2009 tax year with approximately $44.1 million being carried over to 2010 and later tax years. These Federal and state tax credits will begin to expire in 2019; however, the Company expects that all Federal and state tax credits will be fully utilized prior to expiration.

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 2,007,256 shares of common stock under its DRIP/DSPP in 2009 and received proceeds of approximately $49.5 million. The Company may, from time to time, issue additional shares under its DRIP/DSPP to fund capital requirements or working capital needs.

At December 31, 2009, there were 2,992,744 shares of unissued common stock reserved for issuance under various employee and Company stock plans.

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.

Shareowners Rights Plan

In December 1990, OG&E adopted a Shareowners Rights Plan designed to protect shareowners' interests in the event that OG&E was confronted with an unfair or inadequate acquisition proposal. In connection with a corporate restructuring, the Company adopted a substantially identical Shareowners Rights Plan in August 1995. Pursuant to the plan, the Company declared a dividend distribution of one "right" for each share of Company common stock. As a result of the June 1998 two-for-one stock split, each share of common stock is now entitled to one-half of a right. Each right entitles the holder to purchase from the Company one one-hundredth of a share of new preferred stock of the Company under certain circumstances. The rights may be exercised if a person or group announces its intention to acquire, or does acquire, 20 percent or more of the Company's outstanding common stock. Under certain circumstances, the holders of the rights will be entitled to purchase either shares of common stock of the Company or common stock of the acquirer at a reduced percentage of the market value. In October 2000, the Shareowners Rights Plan was amended and restated to extend the expiration date to December 11, 2010 and to change the exercise price of the rights.

The Company's Restated Certificate of Incorporation permits the issuance of a new series of preferred stock with dividends payable other than quarterly.

Earnings Per Share

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

Year ended December 31 *(In millions)*	**2009**	2008	2007
Average Common Shares Outstanding			
Basic average common shares outstanding	**96.2**	92.4	91.7
Effect of dilutive securities:			
Employee stock options and unvested stock grants	---	0.1	0.3
Contingently issuable shares (performance units)	**1.0**	0.3	0.5
Diluted average common shares outstanding	**97.2**	92.8	92.5
Anti-dilutive shares excluded from EPS calculation	---	---	---

9. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 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
0.30% - 1.00%	Garfield Industrial Authority, January 1, 2025	**$ 47.0**
0.42% - 0.74%	Muskogee Industrial Authority, January 1, 2025	**32.4**
0.42% - 0.75%	Muskogee Industrial Authority, June 1, 2027	**56.0**
Total (redeemable during next 12 months)		**$ 135.4**

All of these Bonds are subject to an optional tender at the request of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase. The bond holders, on any business day, can request repayment of the Bond by delivering an irrevocable notice to the tender agent stating the principal amount of the Bond, payment instructions for the purchase price and the business day the Bond is to be purchased. The repayment option may only be exercised by the holder of a Bond for the principal amount. When a tender notice has been received by the trustee, a third party remarketing agent for the Bonds will attempt to remarket any Bonds tendered for purchase. This process occurs once per week. Since the original issuance of these series of Bonds in 1995 and 1997, the remarketing agent has successfully remarketed all tendered bonds. If the remarketing agent is unable to remarket any such Bonds, OG&E is obligated to repurchase such unremarketed Bonds. As OG&E has both the intent and ability to refinance the Bonds on a long-term basis and such ability is supported by an ability to consummate the refinancing, the Bonds are classified as long-term debt in the Company's Consolidated Financial Statements. OG&E believes that it has sufficient liquidity to meet these obligations.

Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of approximately $289.2 million in 2010, which was repaid on January 15, 2010, and $200.0 million in 2014. There are no maturities of the Company's long-term debt in years 2011, 2012 or 2013.

The Company has previously incurred costs related to debt refinancings. Unamortized debt expense and unamortized loss on reacquired debt are classified as Deferred Charges and Other Assets and the unamortized premium and discount on long-term debt is classified as Long-Term Debt, respectively, in the Consolidated Balance Sheets and are being amortized over the life of the respective debt.

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

On June 24, 2009, Enogex issued $200 million of 6.875% 5-year senior notes in a transaction exempt from the registration requirements of the Securities Act of 1933. Enogex applied a portion of the net proceeds from the sale of the new notes to pay the purchase price in a tender offer for its 8.125% notes due January 15, 2010 with the remainder of the net proceeds being used to repay a portion of Enogex's borrowings under its revolving credit agreement and for general corporate purposes. Pursuant to the tender offer, on July 23, 2009, Enogex purchased approximately $110.8 million principal amount of the 8.125% senior notes due January 15, 2010 and those repurchased notes were retired and cancelled.

On November 10, 2009, Enogex issued $250 million of 6.25% 10-year senior notes in a transaction exempt from the registration requirements of the Securities Act of 1933. Enogex applied the net proceeds from the sale of the new notes to repay borrowings under its revolving credit agreement, with any excess net proceeds being invested at the OGE Energy level. Enogex's permanent use of the net proceeds from this debt issuance was to repay a portion of the $289.2 million outstanding aggregate principal amount of Enogex's 8.125% senior notes, which matured on January 15, 2010. On January 15, 2010, the $289.2 million outstanding aggregate principal amount of Enogex's 8.125% senior notes was repaid.

10. Short-Term Debt

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was approximately $175.0 million and $298.0 million at December 31, 2009 and 2008, respectively, at a weighted-average interest rate of 0.27 percent and 0.75 percent, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at December 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	$ 175.0	0.27% (D)	December 6, 2012
OG&E (C)	389.0	10.2	0.14% (D)	December 6, 2012
Enogex (E)	250.0	---	---% (D)	March 31, 2013
	1,235.0	185.2	0.26%	
Cash	58.1	N/A	N/A	N/A
Total	$ 1,293.1	$ 185.2	0.26%	

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 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 December 31, 2009, there were no outstanding borrowings under this revolving credit agreement and approximately $175.0 million in outstanding commercial paper borrowings.

(C) This bank facility is available to back up OG&E's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At December 31, 2009, there was approximately $10.2 million supporting letters of credit. There were no outstanding borrowings under this revolving credit agreement and no outstanding commercial paper borrowings at December 31, 2009.

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

(E) This bank facility is available to provide revolving credit borrowings for Enogex. At December 31, 2009, there were no outstanding borrowings under this revolving credit agreement.

OGE Energy's and OG&E's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the back-up lines of credit could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrades of the ratings of OGE Energy or OG&E would result in an increase in the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes. Any future downgrade of the Company would also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post cash collateral or letters of credit.

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

10. Short-Term Debt

11. Retirement Plans and Postretirement Benefit Plans

In December 2008, the FASB issued "Employer's Disclosures about Postretirement Benefit Plan Assets," which amends previously issued accounting guidance in this area. The new standard requires additional disclosures related to: (i) investment policies and strategies, (ii) categories of plan assets, (iii) fair value measurement of plan assets and (iv) significant concentrations of risk. The Company adopted this new standard effective December 31, 2009 and has presented the additional disclosures below.

Defined Benefit Pension Plan

In October 2009, the Company's qualified defined benefit retirement plan ("Pension Plan") and the Company's qualified defined contribution retirement plan ("401(k) Plan") were amended, effective December 31, 2009, to offer a one-time irrevocable election (the "Choice Program") for eligible employees, depending on their hire date, to select a future retirement benefit combination from the Company's Pension Plan and the Company's 401(k) Plan. Eligible employees hired before February 1, 2000, were allowed to select one of three options as the future retirement benefit combination and eligible employees hired on or after February 1, 2000, and before December 1, 2009, were allowed to select from two options as the future benefit retirement combination as discussed below.

Eligible employees hired before February 1, 2000, were allowed to select one of following three options as the future retirement benefit combination:

Option 1: Stay or participate in the current Pension Plan where employees will receive the greater of the cash balance benefit discussed below under Option 1 for employees hired after February 1, 2000 or a benefit based primarily on years of credited service and the average of the five highest consecutive years of compensation during an employee's last 10 years prior to retirement, with reductions in benefits for each year prior to age 62 unless the employee's age and years of credited service equal or exceed 80. Social Security benefits are deducted in determining benefits payable under the Pension Plan. Also, as part of Option 1, employees will stay in their current 401(k) Plan matching contribution formula where, for each pay period beginning on or after January 1, 2010, the Company contributes to the 401(k) Plan, on behalf of each participant, 50 percent of the participant's contributions up to six percent of compensation for participants who have less than 20 years of service (as defined in the 401(k) Plan) and 75 percent of the participant's contributions up to six percent of compensation for participants who have 20 or more years of service.

Option 2: Freeze the current monthly income benefit under the Pension Plan at December 31, 2009, and, for each pay period beginning on or after January 1, 2010, the Company will also contribute to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

Option 3: Freeze and convert the current Pension Plan benefit at December 31, 2009, which will be based on the lump-sum value of the participant's benefit at December 31, 2009, determined as if the participant had terminated employment and commenced benefit payments on that date, to a stable value account balance which will only accrue annual interest credits in the future, and, for each pay period beginning on or after January 1, 2010, the Company will also contribute to the 401(k) Plan, on behalf of each participant, 100 percent of the contributions up to six percent of compensation.

Eligible employees hired on or after February 1, 2000, and before December 1, 2009, were allowed to select from the following two options as the future retirement benefit combination:

Option 1: Stay or participate in the current Pension Plan's cash balance benefit, under which the Company annually will credit to the employee's account an amount equal to five percent of the employee's annual compensation plus accrued interest, as well as stay in their current 401(k) Plan matching contribution formula where, for each pay period beginning on or after January 1, 2010, the Company contributes to the 401(k) Plan, on behalf of each participant, 100 percent of the participant's contributions up to six percent of compensation.

Option 2: Elect not to participate in or, for those currently participating, freeze the current cash balance benefit under the Pension Plan at December 31, 2009 so that it will only accrue annual interest credits in the future, and, for each pay period beginning on or after January 1, 2010, the Company will also contribute to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

Employees hired or rehired on or after December 1, 2009, will only be eligible to participate in the 401(k) Plan where, for each pay period, the Company will contribute to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

It is the Company's policy to fund the Pension Plan on a current basis based on the net periodic pension expense as determined by the Company's actuarial consultants. The Company could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future. During each of 2009 and 2008, the Company made contributions to its Pension Plan of approximately $50.0 million to help ensure that the Pension Plan maintains an adequate funded status. Such contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. In August 2006, legislation was passed that changed the funding requirement for single- and multi-employer defined benefit pension plans as discussed below. During 2010, the Company may contribute up to $50.0 million to its Pension Plan. The expected contribution to the Pension Plan during 2010 would be a discretionary contribution, anticipated to be in the form of cash, and is not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

At December 31, 2009, the projected benefit obligation and fair value of assets of the Company's Pension Plan and restoration of retirement income plan was approximately $619.2 million and $496.3 million, respectively, for an underfunded status of approximately $122.9 million. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

At December 31, 2008, the projected benefit obligation and fair value of assets of the Company's Pension Plan and restoration of retirement income plan was approximately $554.3 million and $389.9 million, respectively, for an underfunded status of approximately $164.4 million. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

The Company recorded a pension settlement charge and a retirement restoration plan settlement charge in 2007. The pension settlement charge and retirement restoration plan settlement charge did not require a cash outlay by the Company and did not increase the Company's total pension expense or retirement restoration expense over time, as the charges were an acceleration of costs that otherwise would have been recognized as pension expense or retirement restoration expense in future periods.

(In millions)	OG&E (A)	Enogex	OGE Energy	Total
Pension Settlement Charge:				
2007	$ 13.3	$ 0.5	$ 2.9	$ 16.7
Retirement Restoration Plan Settlement Charge:				
2007	$ 0.1	$ ---	$ 2.2	$ 2.3

(A) OG&E's Oklahoma and Arkansas jurisdictional portion of these charges were recorded as a regulatory asset (see Note 1 for a further discussion).

Pension Plan Costs and Assumptions

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the "Pension Protection Act") into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Many of the changes enacted as part of the Pension Protection Act were required to be implemented as of the first plan year beginning in 2008. In accordance with the Pension Protection Act, the Company implemented the following changes to its Pension Plan and its 401(k) Plan, as applicable: (i) effective January 1, 2007, the Company's Pension Plan and 401(k) Plan were amended to incorporate clarifying provisions and changes relating to the Pension Protection Act notice requirements, (ii) effective January 1, 2007, the Company's Pension Plan and 401(k) Plan were amended to allow a non-spouse beneficiary to directly rollover an eligible distribution to an eligible individual retirement account, (iii) effective January 1, 2008, the Company's 401(k) Plan was amended to provide 100 percent vesting after completing three years of service, (iv) for the Company's 401(k) Plan, effective January 18, 2008, that plan was amended to implement an eligible automatic contribution arrangement and provide for a qualified default investment alternative consistent with the U.S. Department of Labor regulations, (v) effective January 1, 2008, terminated vested benefits, as defined in the Pension Plan, are payable to participants who, on or after January 1, 2008, leave the Company prior to retirement with at least three years of vesting service. Participants terminating before completing three years of vesting service and attaining age 65 will not receive a benefit, (vi) effective January 1, 2008, the Company's Pension Plan was amended to incorporate funding-based limitations which restrict, among other things, benefit accruals and the forms in which benefits may be paid if the Pension Plan's funding level falls below certain levels set by the Pension Protection Act and (vii) effective January 18, 2008, the 401(k) Plan was amended so that a participant may elect, in accordance with the 401(k) Plan procedures, to have his or her salary deferral rate to be made in the future automatically increased annually on a date and in an amount as specified by the participant in such election. The Company has taken steps to ensure that its plans, as well as participants and outside administrators, are aware of the changes.

Plan Investments, Policies and Strategies

The Pension Plan assets are held in a trust which follows an investment policy and strategy designed to maximize the long-term investment returns of the trust at prudent risk levels. Common stocks are used as a hedge against moderate inflationary conditions, as well as for participation in normal economic times. Fixed income investments are utilized for high current income and as a hedge against deflation. The Company has retained an investment consultant responsible for the general investment oversight, analysis, monitoring investment guideline compliance and providing quarterly reports to certain of the Company's members and the Company's Investment Committee (the "Investment Committee").

The various investment managers used by the trust operate within the general operating objectives as established in the investment policy and within the specific guidelines established for their respective portfolio. The table below shows the target asset allocation percentages for each major category of Pension Plan assets:

Asset Class	Target Allocation	Minimum	Maximum
Domestic All-Cap Equity	20%	---%	25%
Domestic Equity Passive	10%	---%	60%
Domestic Mid-Cap Equity	10%	---%	10%
Domestic Small-Cap Equity	10%	---%	10%
International Equity	15%	---%	15%
Fixed Income Domestic	35%	30%	70%

The portfolio is rebalanced on an annual basis to bring the asset allocations of various managers in line with the target asset allocation listed above. More frequent rebalancing may occur if there are dramatic price movements in the financial markets which may cause the trust's exposure to any asset class to exceed or fall below the established allowable guidelines.

To evaluate the progress of the portfolio, investment performance is reviewed quarterly. It is, however, expected that performance goals will be met over a full market cycle, normally defined as a three to five year period. Analysis of performance is within the context of the prevailing investment environment and the advisors' investment style. The goal of the trust is to provide a rate of return consistently from three to five percent over the rate of inflation (as measured by the national Consumer Price Index) on a fee adjusted basis over a typical market cycle of no less than three years and no more than five years. Each investment manager is expected to outperform its respective benchmark. Below is a list of each asset class utilized with appropriate comparative benchmark(s) each manager is evaluated against:

Asset Class	Comparative Benchmark(s)
Fixed Income	Barclays Capital Aggregate Index
Equity Index	S&P 500 Index
Value Equity	Russell 1000 Value Index – Short-term
	S&P 500 Index – Long-term
Growth Equity	Russell 1000 Growth Index – Short-term
	S&P 500 Index – Long-term
Mid-Cap Equity	S&P 400 Midcap Index
Small-Cap Equity	Russell 2000 Index
International Equity	Morgan Stanley Capital International Europe, Australia and Far East Index

The fixed income manager is expected to use discretion over the asset mix of the trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies, or its instrumentalities (which have no limits) is limited to five percent of the fixed income portfolio as measured by market value. At least 75 percent of the invested assets must possess an investment grade rating at or above Baa3 or BBB- by Moody's, Standard & Poor's or Fitch Ratings ("Fitch"). The portfolio may invest up to 10 percent of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. The purchase of any of the Company's equity, debt or other securities is prohibited.

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The domestic mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the S&P 400 Midcap Index, small dividend yield, return on equity at or near the S&P 400 Midcap Index and earnings per share growth rate at or near the S&P 400 Midcap Index. The domestic small-cap equity manager will purchase shares of companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and earnings per share growth rate at or near the Russell 2000. The international global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall trust across the global equity markets. The manager is required to operate under certain restrictions including: regional constraints, diversification requirements and percentage of U.S. securities. The Morgan Stanley Capital International Europe, Australia and the Far East Index ("EAFE") is the benchmark for comparative performance purposes. The EAFE Index is a market value weighted index comprised of over 1,000 companies traded on the stock markets of Europe, Australia, New Zealand and the Far East. All of the equities which are purchased for the international portfolio are thoroughly researched. Only companies with a market capitalization in excess of $100 million are allowable. No more than five percent of the portfolio can be invested in any one stock at the time of purchase. All securities are freely traded on a recognized stock exchange and there are no 144-A securities and no over-the-counter derivatives. The following investment categories are excluded: options (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares).

For all domestic equity investment managers, no more than eight percent (five percent for mid-cap and small-cap equity managers) can be invested in any one stock at the time of purchase and no more than 16 percent (10 percent for mid-cap and small-cap equity managers) after accounting for price appreciation. A minimum of 95 percent of the total assets of an equity manager's portfolio must be allocated to the equity markets. Options or financial futures may not be purchased unless prior approval of the Investment Committee is received. The purchase of securities on margin is prohibited as is securities lending. Private placement or venture capital may not be purchased. All interest and dividend payments must be swept on a daily basis into a short-term money market fund for re-deployment. The purchase of any of the Company's equity, debt or other securities is prohibited. The purchase of equity or debt issues of the portfolio manager's organization is also prohibited. The aggregate positions in any company may not exceed one percent of the fair market value of its outstanding stock.

Plan Assets

The following table is a summary of the Pension Plan's assets that are measured at fair value on a recurring basis at December 31, 2009. There were no Level 3 investments held by the Pension Plan at December 31, 2009.

(In millions)	Total	Level 1	Level 2
Common stocks			
U.S. common stocks	$ **152.4**	$ **152.4**	$ ---
Foreign common stocks	**57.2**	**57.2**	---
Bonds, debentures and notes (A)			
Bonds, debentures and notes	**119.1**	---	**119.1**
Mortgage-backed securities	**8.6**	---	**8.6**
U.S. Government obligations			
Mortgage-backed securities	**72.3**	---	**72.3**
U.S. treasury notes and bonds (B)	**22.2**	**22.2**	---
Other securities	**4.5**	---	**4.5**
Commingled fund (C)	**32.8**	---	**32.8**
Common collective trust (D)	**15.9**	---	**15.9**
Foreign government bonds	**5.1**	---	**5.1**
U.S. municipal bonds	**2.5**	---	**2.5**
Foreign mutual funds	**2.0**	**2.0**	---
Foreign preferred stock	**0.9**	**0.9**	---
U.S. mutual funds	**0.8**	**0.8**	---
Total	$ **496.3**	$ **235.5**	$ **260.8**

(A) This category primarily represents U.S. corporate bonds with an investment grade rating at or above Baa3 or BBB- by Moody's, Standard & Poor's or Fitch.
(B) This category represents U.S. treasury notes and bonds with a Moody's rating of Aaa and Government Agency Bonds with a Moody's rating of A1 or higher.
(C) This category represents units of participation in a commingled fund that primarily invest in stocks and bonds of U.S. companies.
(D) This category represents units of participation in an investment pool which primarily invests in commercial paper, repurchase agreements and U.S. treasury notes and bonds and certificates of deposit.

The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical assets or liabilities that the Pension Plan and postretirement benefit plans have 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.

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.

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 Pension Plan's and postretirement benefit plans 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 Pension Plan's and postretirement benefit plans own data. The Pension Plan's and postretirement benefit plans own data used to develop unobservable inputs shall be adjusted if information is reasonably available that indicates that market participants would use different assumptions.

Restoration of Retirement Income Plan

The Company provides a restoration of retirement income plan to those participants in the Company's Pension Plan whose benefits are subject to certain limitations under the Internal Revenue Code (the "Code"). The benefits payable under this restoration of retirement income plan are equivalent to the amounts that would have been payable under the Pension Plan but for these limitations. The restoration of retirement income plan is intended to be an unfunded plan.

The Company expects to pay benefits related to its Pension Plan and restoration of retirement income plan of approximately $47.9 million in 2010, $58.3 million in 2011, $74.4 million in 2012, $73.3 million in 2013, $72.7 million in 2014 and an aggregate of $297.7 million in years 2015 to 2019. These expected benefits are based on the same assumptions used to measure the Company's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members ("postretirement benefits"). Regular, full-time, active employees hired prior to February 1, 2000 whose age and years of credited service total or exceed 80 or have attained age 55 with 10 years of vesting service at the time of retirement are entitled to postretirement medical benefits while employees hired on or after February 1, 2000, are not entitled to postretirement medical benefits. Prior to January 1, 2008, all regular, full-time, active employees whose age and years of credited service total or exceed 80 or have attained age 55 with five years of vesting service at the time of retirement are entitled to postretirement life insurance benefits. Effective January 1, 2008, all regular, full-time, active employees whose age and years of credited service total or exceed 80 or have attained age 55 with three years of vesting service at the time of retirement are entitled to postretirement life insurance benefits. Eligible retirees must contribute such amount as the Company specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. OG&E charges to expense the postretirement benefit costs and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

Plan Assets

The following table is a summary of the postretirement benefit plans' assets that are measured at fair value on a recurring basis at December 31, 2009. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2009.

(In millions)	Total	Level 1	Level 3
Group retiree medical insurance contract (A)	$ **49.3**	$ ---	$ **49.3**
U.S. mutual fund (B)	**4.9**	**4.9**	---
Cash	**0.8**	**0.8**	---
Total	$ **55.0**	$ **5.7**	$ **49.3**

(A) This category represents a group retiree medical insurance contract which invests in a pool of mutual funds, bonds and money market accounts, of which a significant portion is comprised of mortgage-backed securities.
(B) This category represents investments in a U.S. equity mutual fund.

The postretirement benefit plans Level 3 investment includes an investment in a group retiree medical insurance contract. The unobservable input included in the valuation of the contract includes the approach for determining the allocation of the postretirement benefit plans pro-rata share of the total assets in the contract.

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

	Group retiree medical insurance contract
Year Ended December 31 *(In millions)*	**2009**
Balance at January 1	$ **55.1**
Actual return on plan assets relating to assets held at the reporting date	**(5.8)**
Purchases, sales, issuances and settlements, net	---
Transfers in and/or out of Level 3	---
Balance at December 31	$ **49.3**

At December 31, 2009, the accumulated postretirement benefit obligation and fair value of assets of the Company's postretirement benefit plans was approximately $288.0 million and $55.0 million, respectively, for an underfunded status of approximately $233.0 million. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note

1) in the Company's Consolidated Balance Sheet. The amount in Accumulated Other Comprehensive Loss and as a regulatory asset represents a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

At December 31, 2008, the accumulated postretirement benefit obligation and fair value of assets of the Company's postretirement benefit plans was approximately $234.3 million and $57.0 million, respectively, for an underfunded status of approximately $177.3 million. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The amount in Accumulated Other Comprehensive Loss and as a regulatory asset represents a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. Future health care cost trend rates are assumed to be 9.49 percent in 2010 with the rates trending downward to five percent by 2018. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE

Year ended December 31 *(In millions)*	**2009**	2008	2007
Effect on aggregate of the service and interest cost components	**$ 2.4**	$ 2.2	$ 2.3
Effect on accumulated postretirement benefit obligations	**40.3**	28.3	26.9

ONE-PERCENTAGE POINT DECREASE

Year ended December 31 *(In millions)*	**2009**	2008	2007
Effect on aggregate of the service and interest cost components	**$ 1.9**	$ 1.8	$ 1.9
Effect on accumulated postretirement benefit obligations	**32.9**	23.4	22.2

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Medicare Act"). The Medicare Act expanded Medicare to include, for the first time, coverage for prescription drugs. Management expects that the accumulated postretirement benefit obligation ("APBO") for the Company with respect to its postretirement medical plan will be reduced by approximately $50.3 million as a result of savings to the Company resulting from the Medicare Act provided subsidy, which will reduce the Company's costs for its postretirement medical plan by approximately $6.8 million annually. The $6.8 million in annual savings is comprised of a reduction of approximately $3.2 million from amortization of the $50.3 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $3.1 million and a reduction in the service cost due to the subsidy of approximately $0.5 million.

The Company expects to pay gross benefits payments related to its postretirement benefit plans, including prescription drug benefits, of approximately $12.8 million in 2010, $14.1 million in 2011, $15.4 million in 2012, $16.9 million in 2013, $18.4 million in 2014 and an aggregate of $109.5 million in years 2015 to 2019. Based on the current law, the Company expects to receive Federal subsidy receipts provided by the Medicare Act of approximately $1.7 million in 2010, $1.9 million in 2011, $2.1 million in 2012, $2.4 million in 2013, $2.6 million in 2014 and an aggregate of $16.6 million in years 2015 to 2019. The Company received approximately $1.5 million in Federal subsidy receipts in 2009.

Obligations and Funded Status

The following table presents the status of the Company's Pension Plan, the restoration of retirement income plan and the postretirement benefit plans for 2009 and 2008. The benefit obligation for the Company's Pension Plan and the restoration of retirement income plan represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated postretirement benefit obligation. The accumulated postretirement benefit obligation for the Company's Pension Plan and restoration of retirement income plan differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated benefit obligation for the Pension Plan and the restoration of retirement income plan at December 31, 2009 was approximately $558.3 million and $6.4 million, respectively. The accumulated benefit obligation for the Pension Plan and the restoration of retirement income plan at December 31, 2008 was approximately $485.1 million and $4.8 million, respectively. The details of the funded status of the Pension Plan, the restoration of retirement income plan and the postretirement benefit plans and the amounts included in the Consolidated Balance Sheets are as follows:

December 31 *(In millions)*	Pension Plan **2009**	Pension Plan 2008	Restoration of Retirement Income Plan **2009**	Restoration of Retirement Income Plan 2008	Postretirement Benefit Plans **2009**	Postretirement Benefit Plans 2008
Change in Benefit Obligation						
Beginning obligations	**$ (547.0)**	$ (518.0)	**$ (7.3)**	$ (4.0)	**$ (234.3)**	$ (216.8)
Service cost	**(18.1)**	(19.0)	**(0.7)**	(0.7)	**(3.3)**	(3.7)
Interest cost	**(31.4)**	(31.4)	**(0.4)**	(0.4)	**(14.1)**	(13.4)
Plan amendments	**(10.2)**	---	**(0.5)**	---	**---**	---
Plan curtailments	**0.4**	---	**---**	---	**---**	---
Participants' contributions	**---**	---	**---**	---	**(6.8)**	(6.0)
Actuarial gains (losses)	**(39.3)**	(19.5)	**0.1**	(2.7)	**(45.2)**	(9.2)
Benefits paid	**34.7**	40.9	**0.5**	0.5	**15.7**	14.8
Ending obligations	**(610.9)**	(547.0)	**(8.3)**	(7.3)	**(288.0)**	(234.3)
Change in Plans' Assets						
Beginning fair value	**389.9**	514.2	**---**	---	**57.0**	78.5
Actual return on plans' assets	**91.1**	(133.4)	**---**	---	**(7.3)**	(19.2)
Employer contributions	**50.0**	50.0	**0.5**	0.5	**14.2**	6.5
Participants' contributions	**---**	---	**---**	---	**6.8**	6.0
Benefits paid	**(34.7)**	(40.9)	**(0.5)**	(0.5)	**(15.7)**	(14.8)
Ending fair value	**496.3**	389.9	**---**	---	**55.0**	57.0
Funded status at end of year	**$ (114.6)**	$ (157.1)	**$ (8.3)**	$ (7.3)	**$ (233.0)**	$ (177.3)

Net Periodic Benefit Cost

Year ended December 31 *(In millions)*	Pension Plan **2009**	Pension Plan 2008	Pension Plan 2007	Restoration of Retirement Income Plan **2009**	Restoration of Retirement Income Plan 2008	Restoration of Retirement Income Plan 2007	Postretirement Benefit Plans **2009**	Postretirement Benefit Plans 2008	Postretirement Benefit Plans 2007
Service cost	**$ 18.1**	$ 19.0	$ 20.6	**$ 0.7**	$ 0.8	$ 0.6	**$ 3.3**	$ 3.7	$ 4.0
Interest cost	**31.4**	31.4	31.8	**0.4**	0.4	0.5	**14.1**	13.4	12.4
Return on plan assets	**(33.0)**	(43.7)	(43.9)	**---**	---	---	**(6.5)**	(6.5)	(5.9)
Amortization of transition obligation	**---**	---	---		---	---	**2.7**	2.7	2.7
Amortization of net loss	**23.5**	9.3	10.5	**0.3**	0.3	0.2	**5.0**	4.0	6.1
Amortization of unrecognized prior service cost	**0.8**	0.9	5.2	**0.6**	0.6	0.6	**1.0**	1.9	2.1
Settlement	**---**	---	16.7	**---**	---	2.3	**---**	---	---
Net periodic benefit cost (A)	**$ 40.8**	$ 16.9	$ 40.9	**$ 2.0**	$ 2.1	$ 4.2	**$ 19.6**	$ 19.2	$ 21.4

(A) In addition to the approximately $42.8 million, $19.0 million and $45.1 million of net periodic benefit cost recognized in 2009, 2008 and 2007, respectively, the Company recognized the following:

- a reduction in pension expense in 2009 of approximately $2.2 million, an increase in pension expense in 2008 of approximately $10.1 million and a reduction in pension expense in 2007 of approximately $10.1 million to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction which are identified as Deferred Pension Plan Expenses (see Note 1); and
- a reduction in pension expense in 2009 of approximately $3.2 million in the Arkansas jurisdiction to reflect the approval of recovery of OG&E's 2006 and 2007 pension settlement costs in the May 2009 Arkansas rate order which are identified as Deferred Pension Plan Expenses (see Note 1).

The capitalized portion of the net periodic pension benefit cost was approximately $8.4 million, $4.0 million and $5.5 million at December 31, 2009, 2008 and 2007, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $4.1 million, $4.6 million and $4.8 million at December 31, 2009, 2008 and 2007, respectively.

Rate Assumptions

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31	**2009**	2008	2007	**2009**	2008	2007
Discount rate	**5.30%**	6.25%	6.25%	**6.00%**	6.25%	6.25%
Rate of return on plans' assets	**8.50%**	8.50%	8.50%	**8.50%**	8.50%	8.50%
Compensation increases	**4.50%**	4.50%	4.50%	**N/A**	N/A	N/A
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**9.49%**	9.00%	9.00%
Ultimate trend rate	**N/A**	N/A	N/A	**5.00%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2018**	2014	2013

N/A - not applicable

The overall expected rate of return on plan assets assumption remained at 8.50 percent in 2008 and 2009 in determining net periodic benefit cost. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the Pension Plan or postretirement benefit plans. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans' current and expected asset allocation.

Post-Employment Benefit Plan

Disabled employees receiving benefits from the Company's Group Long-Term Disability Plan are entitled to continue participating in the Company's Medical Plan along with their dependents. The post-employment benefit obligation represents the actuarial present value of estimated future medical benefits that are attributed to employee service rendered prior to the date as of which such information is presented. The obligation also includes future medical benefits expected to be paid to current employees participating in the Company's Group Long-Term Disability Plan and their dependents, as defined in the Company's Medical Plan.

The post-employment benefit obligation is determined by an actuary on a basis similar to the accumulated postretirement benefit obligation. The estimated future medical benefits are projected to grow with expected future medical cost trend rates and are discounted for interest at the discount rate and for the probability that the participant will discontinue receiving benefits from the Company's Group Long-Term Disability Plan due to death, recovery from disability, or eligibility for retiree medical benefits. The Company's post-employment benefit obligation was approximately $2.2 million and $2.1 million at December 31, 2009 and 2008, respectively.

Defined Contribution Retirement Plan

The Company provides a 401(k) Plan. Each regular full-time employee of the Company or a participating affiliate is eligible to participate in the 401(k) Plan immediately. All other employees of the Company or a participating affiliate are eligible to become participants in the 401(k) Plan after completing one year of service as defined in the 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to the limitations of the Code. The 401(k) Plan was amended in October 2009, as discussed previously, whereby employees were offered a one-time irrevocable election to either stay in their current 401(k) Plan where the Company matching contributions are discussed below or select an option whereby, effective January 1, 2010, the Company will contribute on behalf of each participant, depending on the option selected, 200 percent of the participant's contributions up to five percent of compensation or 100 percent of the participant's contributions up to six percent of compensation. In the current 401(k) Plan, the Company contributes to the 401(k) Plan each pay period, on behalf of each participant, an amount equal to 50 percent of the participant's contributions up to six percent of compensation for participants whose employment or re-employment date occurred before February 1, 2000 and who have less than 20 years of service, as defined in the 401(k) Plan, and an amount equal to 75 percent of the participant's contributions up to six percent of compensation for participants whose employment or re-employment date occurred before February 1, 2000 and who have 20 or more years of service, as defined in the 401(k) Plan. For participants whose employment or re-employment date occurred on or after February 1, 2000 and before December 1, 2009, under the current 401(k) Plan, the Company contributes 100 percent of the participant's contributions up to six percent of compensation. For participants hired on or after December 1, 2009, the Company contributes, effective January 1, 2010, 200 percent of the participant's contributions up to five percent of compensation. No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Prior to January 1, 2010, the Company's contribution, which was initially allocated for investment to the OGE Energy Corp. Common Stock Fund, was made in shares of the Company's common stock or in cash which was used to invest in the Company's common stock. Once made, the Company's contribution could be reallocated, on any business day, by participants to other available investment options. The 401(k) Plan was amended effective January 1, 2010, whereby the Company's contribution may be directed to any available investment option in the 401(k) Plan. The Company contributed approximately $9.3 million, $8.6 million and $7.6 million in 2009, 2008 and 2007, respectively, to the 401(k) Plan.

Deferred Compensation Plan

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees' 401(k) Plan contributions as well as offering this plan to be competitive in the marketplace.

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers. The Company matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on the option the participant elected under the Choice Program discussed above, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after six years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan. In addition, the Benefits Committee may award discretionary employer contribution credits to a participant under the plan. The Company accounts for the contributions related to the Company's executive officers in this plan as Accrued Benefit Obligations and the Company accounts for the contributions related to the Company's directors in this plan as Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. The investment associated with these contributions is accounted for as Other Property and Investments in the Consolidated Balance Sheets. The appreciation of these investments is accounted for as Other Income and the increase in the liability under the plan is accounted for as Other Expense in the Consolidated Statements of Income.

Supplemental Executive Retirement Plan

The Company provides a supplemental executive retirement plan in order to attract and retain lateral hires or other executives designated by the Compensation Committee of the Company's Board of Directors who may not otherwise qualify for a sufficient level of benefits under the Company's Pension Plan and restoration of retirement income plan. The supplemental executive retirement plan is intended to be an unfunded plan and not subject to the benefit limits imposed by the Code.

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. As discussed in Note 1, on January 1, 2008, Enogex distributed the stock of OERI, which engages in the marketing of natural gas, to OGE Energy and, as a result, OERI is no longer a subsidiary of Enogex. 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 years ended December 31, 2009, 2008 and 2007.

2009	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	**$ 1,751.2**	**$ 401.0**	**$ 657.5**	**$ 619.9**	**$ ---**	**$ (559.9)**	**$ 2,869.7**
Cost of goods sold	**796.3**	**239.9**	**458.8**	**617.7**	**---**	**(555.0)**	**1,557.7**
Gross margin on revenues	**954.9**	**161.1**	**198.7**	**2.2**	**---**	**(4.9)**	**1,312.0**
Other operation and maintenance	**348.0**	**40.9**	**87.2**	**9.2**	**(13.9)**	**(4.6)**	**466.8**
Depreciation and amortization	**187.4**	**20.4**	**43.9**	**0.1**	**10.8**	**---**	**262.6**
Impairment of assets	**0.3**	**0.9**	**1.9**	**---**	**---**	**---**	**3.1**
Taxes other than income	**65.1**	**13.2**	**5.5**	**0.4**	**3.4**	**---**	**87.6**
Operating income (loss)	**$ 354.1**	**$ 85.7**	**$ 60.2**	**$ (7.5)**	**$ (0.3)**	**$ (0.3)**	**$ 491.9**
Total assets	**$ 5,478.1**	**$ 1,597.7**	**$ 866.1**	**$ 125.2**	**$ 2,685.4**	**$ (3,485.8)**	**$ 7,266.7**
Capital expenditures	**$ 600.5**	**$ 71.4**	**$ 166.0**	**$ ---**	**$ 10.2**	**$ (0.3)**	**$ 847.8**

2008	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	$ 1,959.5	$ 625.9	$ 1,053.2	$ 1,529.4	$ ---	$ (1,097.3)	$ 4,070.7
Cost of goods sold	1,114.9	479.7	806.4	1,509.5	---	(1,092.5)	2,818.0
Gross margin on revenues	844.6	146.2	246.8	19.9	---	(4.8)	1,252.7
Other operation and maintenance (A)	351.6	48.2	87.3	12.9	(2.0)	(5.8)	492.2
Depreciation and amortization	155.0	17.5	37.1	0.2	7.7	---	217.5
Impairment of assets	---	---	0.4	---	---	---	0.4
Taxes other than income	59.7	12.7	4.6	0.4	3.1	---	80.5
Operating income (loss)	$ 278.3	$ 67.8	$ 117.4	$ 6.4	$ (8.8)	$ 1.0	$ 462.1
Total assets	$ 4,851.2	$ 1,265.9	$ 836.9	$ 235.1	$ 2,469.1	$ (3,139.7)	$ 6,518.5
Capital expenditures	$ 840.1	$ 93.3	$ 240.2	$ ---	$ 12.9	$ (2.0)	$ 1,184.5

(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.

2007	Electric Utility	Transportation and Storage (B)	Gathering and Processing (B)	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	$ 1,835.1	$ 529.1	$ 799.4	$ 1,541.2	$ ---	$ (907.2)	$ 3,797.6
Cost of goods sold	1,025.1	396.4	603.5	1,513.4	---	(903.7)	2,634.7
Gross margin on revenues	810.0	132.7	195.9	27.8	---	(3.5)	1,162.9
Other operation and maintenance	320.7	48.5	72.1	10.1	(11.3)	(3.3)	436.8
Depreciation and amortization	141.3	17.0	28.7	0.2	8.1	---	195.3
Impairment of assets	---	0.5	---	---	---	---	0.5
Taxes other than income	56.0	11.7	3.7	0.4	3.2	---	75.0
Operating income	$ 292.0	$ 55.0	$ 91.4	$ 17.1	$ ---	$ (0.2)	$ 455.3
Total assets	$ 3,874.9	$ 1,519.3	$ 931.4	$ 253.2	$ 2,297.6	$ (3,638.6)	$ 5,237.8
Capital expenditures	$ 377.3	$ 49.0	$ 125.0	$ 0.2	$ 14.5	$ (8.3)	$ 557.7

(B) Beginning in 2008, Enogex began bifurcating intercompany natural gas purchase and sale transactions based upon the operational sources of the natural gas versus recognizing transactions on a net basis in 2007. As a result, certain 2007 transactions have been reclassified within the segment disclosure for consistency of presentation. However, certain 2007 transactions have not been reclassified as the information is not available. As a result of this reclassification, there is no impact on the Company's consolidated Operating Revenues or Cost of Goods Sold.

13. Commitments and Contingencies

Operating Lease Obligations

The Company has operating lease obligations expiring at various dates, primarily for OG&E railcar leases and Enogex noncancellable operating leases. Future minimum payments for noncancellable operating leases are as follows:

Year ended December 31 *(In millions)*	2010	2011	2012	2013	2014	2015 and Beyond	Total
Operating lease obligations							
OG&E railcars	$ 3.9	$ 38.0	$ ---	$ ---	$ ---	$ ---	$ 41.9
Enogex noncancellable operating leases	2.5	1.6	0.4	---	---	---	4.5
Total operating lease obligations	$ 6.4	$ 39.6	$ 0.4	$ ---	$ ---	$ ---	$ 46.4

Payments for operating lease obligations were approximately $9.2 million, $7.3 million and $6.7 million in 2009, 2008 and 2007, respectively.

OG&E Railcar Lease Agreement

At December 31, 2009, OG&E had a noncancellable operating lease with purchase options, covering 1,462 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. At the end of the lease term, which is January 31, 2011, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual 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 expired on November 2, 2009 and was not replaced.

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

OG&E Coal Transportation Contracts

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

OG&E also filed a complaint at the Surface Transportation Board ("STB") requesting the establishment of reasonable rates, practices and service terms for the transportation of coal from Union Pacific served mines in the southern Powder River Basin, Wyoming to OG&E's Muskogee power plant. OG&E began paying interim shipping rates, subject to refund, while this matter was pending with the STB. On July 24, 2009 the STB issued a decision awarding OG&E a reduction in interim shipping rates to its Muskogee power plant. In 2009, OG&E received a refund of approximately $7.7 million from Union Pacific related to payments OG&E made in 2009. All refund amounts are being passed through to OG&E's customers.

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

OG&E Termination of Wholesale Agreement

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

Public Utility Regulatory Policy Act of 1978

At December 31, 2009, OG&E has agreements with two qualifying cogeneration facilities ("QF") having terms of 15 to 32 years. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978 ("PURPA"). Stated generally, PURPA and the regulations thereunder promulgated by the FERC require OG&E to purchase power generated in a manufacturing process from a QF. The rate for such power to be paid by OG&E was approved by the OCC. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by OG&E; the other is a capacity charge, which OG&E must pay the QF for having the capacity available. However, if no electrical power is made available to OG&E for a period of time (generally three months), OG&E's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is recoverable in rates from customers. For the AES-Shady Point, Inc. ("AES") QF contract for 320 MWs, OG&E purchases 100 percent of the electricity generated by the QF. In addition, effective September 1, 2004, OG&E entered into a new 15-year power purchase agreement for 120 MWs with PowerSmith Cogeneration Project, L.P. ("PowerSmith") in which OG&E purchases 100 percent of electricity generated by PowerSmith.

In 2009, 2008 and 2007, OG&E made total payments to cogenerators of approximately $139.8 million, $152.8 million and $156.8 million, respectively, of which approximately $83.1 million, $84.4 million and $88.9 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as Cost of Goods Sold. The future minimum capacity payments under the contracts are approximately: 2010 – $86.1 million, 2011 – $83.1 million, 2012 – $81.1 million, 2013 – $79.0 million and 2014 – $76.7 million.

OG&E Fuel Minimum Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of approximately $358.8 million, $257.6 million and $232.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. OG&E has entered into future purchase commitments of necessary fuel supplies of approximately: 2010 – $340.0 million, 2011 – $63.1 million, 2012 – $21.1 million and 2013 – $1.8 million. OG&E also has a coal contract for purchases from January 2011 through December 2015. As the coal purchases in this contract for years 2013 through 2015 are valued based on an index price to be determined in the future, these amounts are not disclosed.

OG&E Wind Power Purchase Commitments

OG&E's current wind power portfolio includes: (i) the 120 MW Centennial wind farm, (ii) the 101 MW OU Spirit wind farm placed in service in November and December 2009 and (iii) access to up to 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma from a 15-year contract OG&E entered into with FPL Energy that expires in 2018.

OG&E also received approval on January 5, 2010 from the OCC for two wind power purchase agreements with two wind developers who are to build two new wind farms, totaling 280 MWs, in northwestern Oklahoma. OG&E intends to add this capability to its power-generation portfolio by the end of 2010. Under the terms of the agreements, CPV Keenan is to build a 150 MW wind farm in Woodward County and Edison Mission Energy is to build a 130 MW facility in Dewey County near Taloga. The agreements are both 20-year power purchase agreements, under which the developers are to build, own and operate the wind generating facilities and OG&E will purchase their electric output. See Note 14 for a further discussion.

OG&E purchased wind power from FPL Energy of approximately $4.0 million, $4.4 million and $3.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. OG&E has entered into future wind purchase commitments of approximately: 2010 – $10.2 million, 2011 – $51.3 million, 2012 – $52.0 million, 2013 – $52.2 million, 2014 – $52.6 million and 2015 and beyond – $730.6 million.

OG&E Long-Term Service Agreements

In July 2004, OG&E acquired a 77 percent interest in the McClain Plant. As part of that acquisition, OG&E became subject to an existing long-term parts and service maintenance contract for the upkeep of the natural gas-fired combined cycle generation facility. The contract was initiated in December 1999, and runs for the earlier of 96,000 factored-fired hours or 4,800 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2015. The contract requires payments based on both a fixed and variable cost component, depending on how much the McClain Plant is used. OG&E's share of the estimated obligation under the contract, based on the projected future use of the McClain Plant, is approximately: 2010 – $1.4 million, 2011 – $15.8 million, 2012 – $1.5 million, 2013 – $1.5 million, 2014 – $17.1 million and 2015 and beyond – $1.2 million.

In September 2008, OG&E acquired a 51 percent interest in the Redbud Facility. As part of that acquisition, OG&E became subject to an existing long-term parts and service maintenance contract for the upkeep of the natural gas-fired combined cycle generation facility. The contract was initiated in January 2001, and runs for the earlier of 120,000 factored-fired hours or 4,500 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2025. The contract requires payments based on both a fixed and variable cost component, depending on how much the Redbud Facility is used. OG&E's share of the estimated obligation under the contract, based on the projected future use of the Redbud Facility, is approximately: 2010 – $2.3 million, 2011 – $0.6 million, 2012 – $10.5 million, 2013 – $11.9 million, 2014 – $7.4 million and 2015 and beyond – $70.1 million.

Natural Gas Units

In August 2009, OG&E issued a request for proposal ("RFP") for gas supply purchases for periods from November 2009 through March 2010. The gas supply purchases from January through March 2010 account for approximately 18 percent of the Company's projected 2010 natural gas requirements. The RFP process was completed on September 10, 2009. The contracts resulting from this RFP are tied to various gas price market indices that will expire in 2010. Additional gas supplies to fulfill the OG&E's remaining 2010 natural gas requirements will be acquired through additional RFPs in early to mid-2010, along with monthly and daily purchases, all of which are expected to be made at market prices.

Coal

In August 2009, OG&E issued an RFP for coal supply purchases for periods from January 2011 through December 2015. The RFP process was completed during the fourth quarter of 2009 and resulted in two new coal contracts expiring in 2015. The coal supply purchases account for approximately 50 percent of the Company's projected coal requirements during that timeframe. Additional coal supplies to fulfill the Company's remaining 2011 through 2015 coal requirements will be acquired through additional RFPs.

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. OERI's new demand fee obligations, net of this turn back and other immaterial release agreements, are estimated at approximately $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.

Agreement with Midcontinent Express Pipeline, LLC

In December 2006, Enogex entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC ("MEP") for a primary term of 10 years (subject to possible extension) that gives MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP lease agreement is currently 272 million cubic feet per day, with the quantity ultimately to be leased subject to being increased by mutual agreement pursuant to the lease agreement. In addition to MEP's lease of Enogex's capacity, the MEP project included construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. In support of the MEP lease agreement, Enogex constructed approximately 43 miles of 24-inch steel pipe in Woods and Major counties in Oklahoma, and added 24,000 horsepower of electric-driven compression in Bennington, Oklahoma. Enogex's capital expenditures allocated to its support of the MEP lease agreement were approximately $99 million.

On July 25, 2008, the FERC issued its order approving the MEP project including the approval of a limited jurisdiction certificate authorizing the Enogex lease agreement with MEP denying the request for consolidation and rejecting all claims raised by protestors regarding the lease agreement. Accordingly, Enogex proceeded with the construction of facilities necessary to implement this service. On August 25, 2008, the same protestor filed a request for rehearing which the FERC denied. Enogex commenced service to MEP under the lease agreement on June 1, 2009. On July 16, 2009, the protestor filed, with the United States Court of Appeals for the District of Columbia Circuit, a petition for review of the FERC's orders approving the MEP construction and the MEP lease of capacity from Enogex requesting that such orders be modified or set aside on the grounds that they are arbitrary, capricious and contrary to law. The petitioner, the FERC and intervening parties have been given an opportunity to brief the issues. Enogex expects to participate in the filing of a joint intervenors' brief in support of the FERC's order in this matter, which final briefing is scheduled to be completed in the third quarter of 2010.

In 2009, OERI entered into an FTSA with MEP for 10,000 Dth/day of firm capacity on the pipeline. The FTSA was for a five-year term beginning with the in-service date of the MEP pipeline in June 2009 with an annual demand fee of approximately $2.1 million. OERI's demand fee obligations are estimated at approximately $2.1 million for each of the years 2010 through 2013; and $0.8 million in 2014.

Natural Gas Measurement Cases

United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E. (U.S. District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) *United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al.* (U.S. District Court for the Eastern District of Louisiana, Case No. 97-2089; U.S. District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with the plaintiff's complaint, which was a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the Federal government, alleged: (a) each of the named defendants had improperly or intentionally mismeasured gas (both volume and British thermal unit ("Btu") content) purchased from Federal and Indian lands which resulted in the under reporting and underpayment of gas royalties owed to the Federal government; (b) certain provisions generally found in gas purchase contracts were improper; (c) transactions by affiliated companies were not arms-length; (d) excess processing cost deduction; and (e) failure to account for production separated out as a result of gas processing. Grynberg sought 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. Various appeals and hearings were held in this matter from 2006 to late 2009. In October 2009, this matter concluded with the dismissal of all complaints against all Company parties. The Company now considers this case closed and, as a result, during the third quarter of 2009, the Company reversed a reserve of approximately $1.5 million that was originally established with the 1999 acquisition of Transok.

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

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

The class certification issues were briefed and argued by the parties in 2005 and proposed findings of facts and conclusions of law on class certification were filed in 2007. On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On February 10, 2010 the court heard arguments on the rehearing. No ruling on this motion has been made.

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

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

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

The class certification issues were briefed and argued by the parties in 2005 and proposed findings of facts and conclusions of law on class certification were filed in 2007. On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On February 10, 2010 the court heard arguments on the rehearing. No ruling on this motion has been made.

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

Farris Buser Litigation

On July 22, 2005, Enogex along with certain other unaffiliated co-defendants was served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including Enogex and its subsidiaries, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs' wells. The plaintiffs assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages in excess of $10,000, plus attorneys' fees and costs, and punitive damages in excess of $10,000. Enogex and its subsidiaries filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs' right to conduct discovery and the possible re-filing of their allegations in the petition against the Enogex companies. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Company (collectively, "BP"), filed a cross claim against Products seeking indemnification and/or contribution from Products based upon the 1997 sale of a third-party interest in one of Products natural gas processing plants. On May 17, 2006, the plaintiffs filed an amended petition against Enogex and its subsidiaries. Enogex and its subsidiaries filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion was held on November 20, 2006 and the court denied Enogex's motion. Enogex filed an answer to the amended petition and BP's cross claim on January 16, 2007. Based on Enogex's investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to continue vigorously defending this case.

Pipeline Rupture

On November 14, 2008, a natural gas gathering pipeline owned by Enogex ruptured in Grady County, near Alex, Oklahoma, resulting in a fire that caused injuries to one resident and destroyed three residential structures. The cause of the rupture is not known and an investigation of the incident is ongoing. The damaged pipeline has been repaired and the pipeline is back in service. After the incident, Enogex coordinated and assisted the affected residents. Enogex resolved matters with two of the residents and Enogex continues to seek resolution with a remaining resident. This resident filed a legal action in May 2009 in the District Court of Cleveland County, Oklahoma, against OGE Energy and Enogex seeking to recover actual and punitive damages in excess of $10,000. The parties participated in a mediation of the pending action in August but were unable to resolve the action. Enogex has requested information regarding property and non-economic damage from the plaintiffs but has not yet received a response. Enogex intends to make full payment for actual medical expenses and property damages in this case. While the Company cannot predict the outcome of this lawsuit at this time, the Company intends to vigorously defend any demand for punitive damages or excessive compensatory damages in this case and believes that its ultimate resolution will not be material to the Company's consolidated financial position or results of operations.

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. On March 10, 2009, the Oklahoma Attorney General, OG&E, OG&E Shareholders Association and the Staff of the Public Utility Division of the OCC all filed briefs arguing that the application should be dismissed. On December 9, 2009 the OCC issued an order dismissing the plaintiffs' request for a modification of the OCC order which authorizes OG&E to collect and remit sales tax on franchise fee charges. In its December 9, 2009 order, the OCC advised the plaintiffs that the ruling does not address the question of whether OG&E's collection and remittance of such sales tax should be discontinued prospectively. On December 21, 2009, the plaintiffs filed a motion at the Oklahoma Supreme Court asking the court to deny OG&E's writ of prohibition and to remand the cause to the District Court. On December 29, 2009, the Oklahoma Supreme Court declared the plaintiffs' motion moot. On January 27, 2010, the OCC Staff filed a motion asking the OCC to dismiss the cause and close the cause at the OCC. If the OCC Staff's motion is granted, the plaintiffs would be required to file a new cause in order to ask for prospective relief. In its motion, the OCC Staff stated that the plaintiff's counsel advised the OCC Staff counsel that the plaintiffs have no desire to seek a determination regarding prospective relief from the OCC. It is unknown whether the plaintiffs will attempt to continue the District Court action. OG&E believes that the lawsuit is without merit.

Oxley Litigation

OG&E has been sued by John C. Oxley D/B/A Oxley Petroleum et al. in the District Court of Haskell County, Oklahoma. This case has been pending for more than 11 years. The plaintiffs alleged that OG&E breached the terms of contracts covering several wells by failing to purchase gas from the plaintiffs in amounts set forth in the contracts. The plaintiffs' most recent Statement of Claim describes approximately $2.7 million in take-or-pay damages (including interest) and approximately $36 million in contract repudiation damages (including interest), subject to the limitation described below. In 2001, OG&E agreed to provide the plaintiffs with approximately $5.8 million of consideration and the parties agreed to arbitrate the dispute. Consequently, OG&E will only be liable for the amount, if any, of an arbitration award in excess of $5.8 million. The arbitration hearing was completed recently and the next step is briefing by the parties. While the Company cannot predict the precise outcome of the arbitration, based on the information known at this time, OG&E believes that this lawsuit will not have a material adverse effect on the Company's consolidated financial position or results of operations.

Environmental Laws and Regulations

The activities of OG&E and Enogex are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators, regulating future construction activities to avoid endangered species or enjoining some or all of the operations of facilities deemed in noncompliance with permits issued pursuant to such environmental laws and regulations. In most instances, the applicable regulatory requirements relate to water and air pollution control or solid waste management measures. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes can impose burdensome liability for costs required to clean up and restore sites where substances or wastes have been disposed or otherwise released into the environment. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment. OG&E and Enogex handle some materials subject to the requirements of the Federal Resource Conservation and Recovery Act and the Federal Water Pollution Control Act of 1972, as amended ("Federal Clean Water Act") and comparable state statutes, prepare and file reports and documents pursuant to the Toxic Substance Control Act and the Emergency Planning and Community Right to Know Act and obtain permits pursuant to the Federal Clean Air Act and comparable state air statutes.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's or Enogex's facilities. Historically, OG&E's and Enogex's total expenditures for environmental control facilities and for remediation have not been significant in relation to its consolidated financial position or results of operations. The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards may increase the cost of conducting business.

Air

Sulfur Dioxide

The 1990 Federal Clean Air Act includes an acid rain program to reduce sulfur dioxide ("SO2") emissions. Reductions were obtained through a program of emission (release) allowances issued by the U.S. Environmental Protection Agency ("EPA") to power plants covered by the acid rain program. Each allowance is worth one ton of SO2 released from the chimney. Plants may only release as much SO2 as they have allowances. Allowances may be banked and traded or sold nationwide. Beginning in 2000, OG&E became subject to more stringent SO2 emission requirements in Phase II of the acid rain program. These lower limits had no significant financial impact due to OG&E's earlier decision to burn low sulfur coal. In 2009, OG&E's SO2 emissions were below the allowable limits.

The EPA allocated SO2 allowances to OG&E starting in 2000 and OG&E started banking allowances in 2001. OG&E sold 10,000 banked allowances in 2009 for approximately $0.8 million. Also, during 2009, OG&E received proceeds of approximately $0.1 million from the annual EPA spot (year 2009) and seven-year advance (year 2016) allowance auctions that were held in March 2009.

Nitrogen Oxides

On January 25, 2010, the EPA released a rule strengthening the National Ambient Air Quality Standards ("NAAQS") for oxides of nitrogen as measured by nitrogen dioxide ("NO2") which is effective March 26, 2011. The rule establishes a new one-hour standard and monitoring requirements, as well as an approach for implementing the new standard. Oklahoma is currently in attainment with the new standard and it is anticipated that Oklahoma will be designated "unclassifiable" in 2012 because the new monitoring requirements will not yet be fully implemented. After the new monitoring network is deployed and has collected three years of air quality data, the EPA will re-designate areas in 2016 or 2017 based on the new data. It is currently anticipated that Oklahoma will be designated "attainment" at that time.

With respect to the nitrogen oxide ("NOX") regulations of the acid rain program, OG&E committed to meeting a 0.45 lbs/MMBtu NOX emission level in 1997 on all coal-fired boilers. As a result, OG&E was eligible to exercise its option to extend the effective date of the lower emission requirements from the year 2000 until 2008. The regulations required that OG&E achieve a NOX emission level of 0.40 lbs/MMBtu for these boilers which began in 2008. OG&E's average NOX emissions from its coal-fired boilers for 2009 were approximately 0.319 lbs/MMBtu.

Particulate Matter

On September 21, 2006, the EPA lowered the 24-hour fine particulate ambient standard while retaining the annual standard at its current level and promulgated a new standard for inhalable coarse particulates. Based on past monitoring data, it appears that Oklahoma may be able to remain in attainment with these standards. However if parts of Oklahoma do become "non-attainment", reductions in emissions from OG&E's coal-fired boilers could be required which may result in significant capital and operating expenditures.

Ozone

Currently, the EPA has designated Oklahoma "in attainment" with the ambient standard for ozone of 0.08 parts per million ("PPM"). In March 2008, the EPA lowered the ambient primary and secondary standards to 0.075 PPM. Oklahoma had until March 2009 to designate any areas of non-attainment within the state, based on ozone levels in 2006 through 2008. Following the state's designation, the EPA was expected to determine a final designation by March 2010. States were to be required to meet the ambient standards between 2013 and 2030, with deadlines depending on the severity of their ozone level. Oklahoma City and Tulsa were the most likely areas to be designated non-attainment in Oklahoma. On September 16, 2009, the EPA announced that they would reconsider the 2008 national primary and secondary ozone standards to ensure they are scientifically sound and protective of human health. The EPA also proposed to keep the 2008 standards unchanged for the purpose of attainment and non-attainment area designations. On January 19, 2010, the EPA published a decision to extend by one year the deadline for promulgating initial area designations for the NAAQS that were promulgated in March 2008. The new deadline is March 12, 2011.

Greenhouse Gases

There also is growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation and regulation at the Federal level, actions at the state level, litigation relating to greenhouse gas emissions and pressure for greenhouse gas emission reductions from investor organizations and the international community. Recently, two Federal courts of appeal have reinstated nuisance-type claims against emitters of carbon dioxide, including several utility companies, alleging that such emissions contribute to global warming. Although the Company is not a defendant in either proceeding, additional litigation in Federal and state courts over these issues is expected.

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

Interstate Transport

On April 25, 2005, the EPA published a finding that all 50 states failed to submit the interstate pollution transport plans required by the Federal Clean Air Act as a result of the adoption of the revised ambient ozone and fine particle standards. Failure to submit these implementation plans began a two-year timeframe, starting on May 25, 2005, during which states must submit a demonstration to the EPA that they do not affect air quality in downwind states. The demonstration was properly submitted by Oklahoma to the EPA on May 7, 2007, and additional information was submitted by the state to the EPA on December 5, 2007. On June 5, 2009, a lawsuit was filed by WildEarth Guardians, a third-party, in an attempt to force the EPA to act because the EPA had not yet approved transport state implementation plans from California, Colorado, Idaho, New Mexico, North Dakota, Oklahoma and Oregon. A consent decree was proposed December 7, 2009 and the comment period closed January 5, 2010. The outcome of this matter is uncertain at this time.

EPA 2008 Information Request

In July 2008, OG&E received a request for information from the EPA regarding Federal Clean Air Act compliance at OG&E's Muskogee and Sooner generating plants. In recent years, the EPA has issued similar requests to numerous other electric utilities seeking to determine whether various maintenance, repair and replacement projects should have required permits under the Federal Clean Air Act's new source review process. OG&E believes it has acted in full compliance with the Federal Clean Air Act and new source review process and is cooperating with the EPA. On August 28, 2008, OG&E submitted information to the EPA and submitted additional information on October 31, 2008. OG&E cannot predict what, if any, further actions the EPA may take with respect to this matter.

Title V Permits and Emission Fees

At December 31, 2009, OG&E had received Title V permits for all of its generating stations and intends to continue to renew these permits as necessary. Air permit fees for OG&E's generating stations were approximately $0.9 million in 2009 and for Enogex's facilities were approximately $0.2 million in 2009.

Waste

OG&E has sought and will continue to seek, new pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2009, OG&E obtained refunds of approximately $2.4 million from its recycling efforts. This figure does not include the additional savings gained through the reduction and/or avoidance of disposal costs and the reduction in material purchases due to the reuse of existing materials. Similar savings are anticipated in future years.

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 and December 4, 2009. OG&E provided comments on the initial draft permit and will provide additional comments on the final draft permit during the public comment period. In addition, OG&E filed OPDES permit renewal applications for its Muskogee, Mustang and Horseshoe Lake generating stations on March 4, 2009, April 3, 2009 and October 29, 2009, respectively.

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 Consolidated Financial Statements. Except as otherwise stated above, in Note 14 below and in Item 3 of this Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

14. Rate Matters and Regulation

Regulation and Rates

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's wholesale electric tariffs, transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the U.S. Department of Energy ("DOE") has jurisdiction over some of OG&E's facilities and operations. For the year ended December 31, 2009, approximately 89 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and three percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of the Company. The order required that, among other things, (i) the Company permit the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E, (ii) the Company employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) the Company refrain from pledging OG&E assets or income for affiliate transactions. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of the Company and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates.

Completed Regulatory Matters

OG&E Arkansas Rate Case Filing

On August 29, 2008, OG&E filed with the APSC an application for an annual rate increase of approximately $26.4 million to recover, among other things, costs for investments in the 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. On March 18, 2009, OG&E, the APSC Staff and the Arkansas Attorney General filed a settlement agreement in this matter calling for a general rate increase of approximately $13.6 million. This settlement agreement also allows implementation of OG&E's "time-of-use" tariff which allows participating customers to save on their electricity bills by shifting some of the electricity consumption to times when demand for electricity is lowest. On May 20, 2009, the APSC approved a general rate increase of approximately $13.3 million, which excludes approximately $0.3 million in storm costs discussed below. OG&E implemented the new electric rates effective June 1, 2009.

OG&E 2008 Arkansas Storm Cost Filing

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

OG&E System Hardening Filing

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

Security Enhancements

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

OG&E FERC Formula Rate Filing

On November 30, 2007, OG&E made a filing at the FERC to increase its transmission rates to wholesale customers moving electricity on OG&E's transmission lines. Interventions and protests were due by December 21, 2007. On January 31, 2008, the FERC issued an order: (i) conditionally accepting the rates, (ii) suspending the effectiveness of such rates for five months, to be effective July 1, 2008, subject to refund, (iii) establishing hearing and settlement judge procedures and (iv) directing OG&E to make a compliance filing. In July 2008, rates were implemented in an annual increase of approximately $2.4 million, subject to refund. On June 25, 2009, the FERC issued an order approving an approximate $1.3 million increase in revenues from OG&E's transmission customers compared to the approximate $2.4 million increase in revenues previously implemented in July 2008. In accordance with the FERC formula, overcollections for the prior period are to be credited to transmission customers as part of the calculation of the rates to be paid in 2010.

OG&E 2009 Oklahoma Rate Case Filing

On February 27, 2009, OG&E filed its rate case with the OCC requesting a rate increase of approximately $110 million. On July 24, 2009, the OCC issued an order authorizing: (i) an annual net increase of approximately $48.3 million in OG&E's rates to its Oklahoma retail customers, which includes an increase in the residential customer charge from $6.50/month to $13.00/month, (ii) creation of a new recovery rider to permit the recovery of up to $20 million of capital expenditures and operation and maintenance expenses associated with OG&E's smart grid project in Norman, Oklahoma, which was implemented in February 2010, (iii) continued utilization of a return on equity ("ROE") of 10.75 percent under various recovery riders previously approved by the OCC and (iv) recovery through OG&E's fuel adjustment clause of approximately $4.8 million annually of certain expenses that historically had been recovered through base rates. New electric rates were implemented August 3, 2009. OG&E expects the impact of the rate increase on its customers and service territory to be minimal over the next 12 months as the rate increase will be more than offset by lower fuel costs attributable to prior fuel over recoveries and from lower than forecasted fuel costs in 2010.

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. On August 12, 2009, all parties to this case signed a settlement agreement in this matter, stating that OG&E's generation and fuel procurement processes and costs during the 2007 calendar year were prudent. A hearing on the settlement agreement was held on September 10, 2009 and the administrative law judge recommended approval of the settlement agreement. On October 15, 2009, the OCC issued an order adopting the findings in the settlement agreement.

OG&E OU Spirit Wind Power Project

OG&E signed contracts on July 31, 2008 for approximately 101 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with OU Spirit. As discussed below, OU Spirit is part of OG&E's goal to increase its wind power generation portfolio in the near future. On July 30, 2009, OG&E filed an application with the OCC requesting pre-approval to recover from Oklahoma customers the cost to construct OU Spirit at a cost of approximately $265.8 million. On October 15, 2009, all parties to this case signed a settlement agreement that would provide pre-approval of OU Spirit and authorize OG&E to begin recovering the costs of OU Spirit through a rider mechanism as the 44 turbines were placed into service in November and December 2009 and began delivering electricity to OG&E's customers. The rider will be in effect until OU Spirit is added to OG&E's regulated rate base as part of OG&E's next general rate case, which is expected to be based on a 2010 test year and completed in 2011, at which time the rider will cease. The settlement agreement also assigns to OG&E's customers the proceeds from the sale of OU Spirit renewable energy credits to the University of Oklahoma. The settlement agreement permits the recovery of up to $270 million of eligible construction costs, including recovery of the costs of the conservation project for the lesser prairie chicken as discussed below. The net impact on the average residential customer's 2010 electric bill is estimated to be approximately 90 cents per month, decreasing to 80 cents per month in 2011. On November 25, 2009, OG&E received an order from the OCC approving the settlement agreement in this case, with the rider being implemented on December 4, 2009. Capital expenditures associated with this project were approximately $270 million.

In connection with OU Spirit, in January 2008, OG&E filed with the SPP for a Large Generator Interconnection Agreement ("LGIA") for this project. Since January 2008, the SPP has been studying this requested interconnection to determine the feasibility of the request, the impact of the interconnection on the SPP transmission system and the facilities needed to accommodate the interconnection. Given the backlog of interconnection requests at the SPP, there has been significant delay in completing the study process and in OG&E receiving a final LGIA. On May 29, 2009, OG&E executed an interim LGIA, allowing OU Spirit to interconnect to the transmission grid, subject to certain conditions. In connection with the interim LGIA, OG&E posted a letter of credit with the SPP of approximately $10.9 million, which was later reduced to approximately $9.9 million in October 2009 and further reduced to approximately $9.2 million in February 2010, related to the costs of upgrades required for OG&E to obtain transmission service from its new OU Spirit wind farm. The SPP filed the interim LGIA with the FERC on June 29, 2009. On August 27, 2009, the FERC issued an order accepting the interim LGIA, subject to certain conditions, which enables OU Spirit to interconnect into the transmission grid until the final LGIA can be put in place, which is expected by mid-2010.

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

OG&E Renewable Energy Filing

OG&E announced in October 2007 its goal to increase its wind power generation over the following four years from its then current 170 MWs to 770 MWs and, as part of this plan, on December 8, 2008, OG&E issued an RFP to wind developers for construction of up to 300 MWs of new capability, which OG&E intends to add to its power-generation portfolio by the end of 2010. In June 2009, OG&E announced that it had selected a short list of bidders for a total of 430 MWs and that it was considering acquiring more than the approximately 300 MWs of wind energy originally contemplated in the initial RFP. On September 29, 2009, OG&E announced that, from its short list, it had reached agreements with two developers who are to build two new wind farms, totaling 280 MWs, in northwestern Oklahoma. Under the terms of the agreements, CPV Keenan is to build a 150 MW wind farm in Woodward County and Edison Mission Energy is to build a 130 MW facility in Dewey County near Taloga. The agreements are both 20-year power purchase agreements, under which the developers are to build, own and operate the wind generating facilities and OG&E will purchase their electric output. On October 30, 2009, OG&E filed separate applications with the OCC seeking pre-approval for the recovery of the costs associated with purchasing power from these projects. On December 9, 2009, all parties to these cases signed settlement agreements whereby the stipulating parties requested that the OCC issue orders: (i) finding that the execution of the power purchase agreements complied with the OCC competitive bidding rules, are prudent and are in the public's interest, (ii) approving the power purchase agreements and (iii) authorizing OG&E to recover the costs of the power purchase agreements through OG&E's fuel adjustment clause. On January 5, 2010, OG&E received an order from the OCC approving the power purchase agreements and authorizing OG&E to recover the costs of the power purchase agreements through OG&E's fuel adjustment clause. The two wind farms are expected to be in service by the end of 2010. Negotiations with the third bidder on OG&E's short list announced in June, for an additional 150 MWs of wind energy from Texas County were terminated in early October. OG&E will continue to evaluate renewable opportunities to add to its power-generation portfolio in the future.

OG&E Windspeed Transmission Line Project

OG&E filed an application on May 19, 2008 with the OCC requesting pre-approval to recover from Oklahoma customers the cost to construct a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma ("Windspeed") at a construction cost of approximately $211 million, plus approximately $7 million in AFUDC, for a total of approximately $218 million. This transmission line is a critical first step to increased wind development in western Oklahoma. In the application, OG&E also requested authorization to implement a recovery rider to be effective when the transmission line is completed and in service, which is expected during April 2010. Finally, the application requested the OCC to approve new renewable tariff offerings to OG&E's Oklahoma customers. A settlement agreement was signed by all parties in the matter on July 31, 2008. Under the terms of the settlement agreement, the parties agreed that OG&E will: (i) receive pre-approval for construction of a the Windspeed transmission line and a conclusion that the construction costs of the transmission line are prudent, (ii) receive a recovery rider for the revenue requirement of the $218 million in construction costs and AFUDC when the transmission line is completed and in service until new rates are implemented in an expected 2011 rate case and (iii) to the extent the construction costs and AFUDC for the transmission line exceed $218 million, OG&E be permitted to show that such additional costs are prudent and allowed to be recovered. On September 11, 2008, the OCC issued an order approving the settlement agreement. At December 31, 2009, the construction costs and AFUDC incurred were approximately $184.9 million. Separately, on July 29, 2008, the SPP Board of Directors approved the proposed transmission line discussed above. On February 2, 2009, OG&E received SPP approval to begin construction of the transmission line and the associated Woodward District EHV substation. In 2009, OG&E received a favorable outcome in five local court cases challenging OG&E's use of eminent domain to obtain rights-of-way. The capital expenditures related to this project are presented in the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

Market-Based Rate Authority

On December 22, 2003, OG&E and OERI filed a triennial market power update with the FERC based on the supply margin assessment test. On May 13, 2004, the FERC directed all utilities with pending three year market-based reviews to revise the generation market power portion of their three year review to address two new interim tests, a pivotal supplier screen test and a market share screen test. On February 7, 2005, OG&E and OERI submitted a compliance filing to the FERC that applied the interim tests to OG&E and OERI. On June 7, 2005, the FERC issued an order finding that OG&E and OERI had failed the market share screen test meant to determine whether entities with market-based rate authority have market power in wholesale power markets. Based on the failed market share screen test, the FERC established a rebuttable presumption that OG&E and OERI have the ability to exercise market power in OG&E's control area. On August 8, 2005, OG&E and OERI informed the FERC that they would: (i) adopt the FERC default rate mechanism for sales of one week or less to loads that sink in OG&E's control area and (ii) commit not to enter into any sales with a duration of between one week and one year to loads that sink in OG&E's control area. OG&E and OERI also informed the FERC that any new agreements for long-term sales (one year or longer in duration) to loads that sink in OG&E's control area would be filed with the FERC and that OG&E and OERI would not make such sales under their respective market-based rate tariffs. On March 21, 2006, the FERC issued an order conditionally accepting OG&E's and OERI's proposal to mitigate the presumption of market power in OG&E's control area. First, the FERC accepted the additional information related to first-tier markets submitted by OG&E and OERI, and concluded that OG&E and OERI satisfy the FERC's generation market power standard for directly interconnected first-tier control areas.

Second, the FERC directed OG&E and OERI to make certain revisions to its mitigation proposal and file a cost-based rate tariff for short-term sales (one week or less) made within OG&E's control area. The FERC also expanded the scope of the proposed mitigation to all sales made within OG&E's control area (instead of only to sales sinking to load within OG&E's control area). As part of the market-based rate matter, OG&E and OERI have filed a series of tariff revisions to comply with the FERC orders and such revisions have been accepted by the FERC. Also, as part of the mitigation for the failed market share screen test discussed above, on an ongoing basis, OG&E and OERI file change of status reports and triennial market power reports according to the FERC orders and regulations. In July 2009, OG&E and OERI filed a triennial market power update with the FERC which reported that there have been no significant changes to OG&E's and OERI's market-based rate authority.

OG&E Conservation and Energy Efficiency Programs

In June and September 2009, OG&E filed applications with the APSC and the OCC seeking approval of a comprehensive Demand Program portfolio designed to build on the success of its earlier programs and further promote energy efficiency and conservation for each class of OG&E customers. Several programs are proposed in these applications, ranging from residential weatherization to commercial lighting. In seeking approval of these new programs, OG&E also seeks recovery of the program and related costs through a rider that would be added to customers' electric bills. In Arkansas, OG&E's program is expected to cost approximately $2 million over an 18-month period and is expected to increase the average residential electric bill by less than $1.00 per month. In Oklahoma, OG&E's program is expected to cost approximately $45 million over three years and is expected to increase the average residential electric bill by less than $1.00 per month in 2010 and by approximately $1.40 per month in 2011 and 2012 depending on the success of the programs. In addition to program cost recovery, the OCC also granted OG&E recovery of: (i) lost revenues resulting from the reduced Kilowatt-hour sales between rate cases and (ii) performance-based incentives of 15 percent of the net savings associated with the programs. A hearing in the APSC matter was held on October 29, 2009 and OG&E received an order in this matter on February 3, 2010. A settlement agreement was signed in the OCC matter by several parties to this case on January 15, 2010 with a hearing being held on January 21, 2010, where the parties who had not previously signed the settlement agreement indicated that they did not oppose the settlement agreement. OG&E received an order in the OCC matter on February 10, 2010.

Pending Regulatory Matters

SPP Transmission/Substation Projects

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

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

In 2007, the SPP notified OG&E to construct approximately 44 miles of new 345 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 June 2012. The capital expenditures related to this project are presented in the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

In January 2009, OG&E received notification from the SPP to begin construction on approximately 50 miles of new 345 kV transmission line and substation upgrades at OG&E's Sunnyside substation, among other projects. In April 2009, Western Farmers Electric Cooperative ("WFEC") assigned to OG&E the construction of 50 miles of line designated by the SPP to be built by the WFEC. The new line will extend from OG&E's Sunnyside substation near Ardmore, Oklahoma, approximately 100 miles to the Hugo substation owned by the WFEC near Hugo, Oklahoma. OG&E began preliminary line routing and acquisition of rights-of-way in June 2009. When construction is completed, which is expected in April 2012, the SPP will allocate a portion of the annual revenue requirement to OG&E customers according to the base-plan funding mechanism as provided in the SPP tariff for application to such improvements. The capital expenditures related to this project are presented in the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

On April 28, 2009, the SPP approved a set of 345 kV projects referred to as "Balanced Portfolio 3E". Balanced Portfolio 3E includes four projects to be built by OG&E and includes: (i) construction of approximately 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, which is expected to be in service by December 2014, (ii) construction of approximately 72 miles of transmission line from OG&E's Woodward District EHV substation in a southwestern direction to the Oklahoma/Texas Stateline to a companion transmission line to be built by Southwestern Public Service to its Tuco substation at a cost of approximately $120 million for OG&E, which is expected to be in service by April 2014, (iii) construction of approximately 38 miles of transmission line from OG&E's Sooner substation in an eastern direction to the Grand River Dam Authority Cleveland substation at an estimated cost of approximately $41 million for OG&E, which is expected to be in service by December 2012 and (iv) construction of a new substation near Anadarko which is expected to consist of a 345/138 kV transformer and substation breakers and will be built in OG&E's portion of the Cimarron-Lawton East Side 345 kV line at an estimated cost of approximately $8 million for OG&E, which is expected to be in service by December 2012. On June 19, 2009, OG&E received a notice to construct the Balanced Portfolio 3E projects from the SPP. On July 23, 2009, OG&E responded to the SPP that OG&E will construct the Balanced Portfolio 3E projects discussed above beginning in early 2010. The capital expenditures related to the Balanced Portfolio 3E projects are presented in the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

OG&E Smart Grid Application

In February 2009, the President signed into law the ARRA. Several provisions of this law relate to issues of direct interest to the Company including, in particular, financial incentives to develop smart grid technology, transmission infrastructure and renewable energy. After review of the ARRA, OG&E filed a grant request on August 4, 2009 for $130 million with the DOE to be used for the Smart Grid application in OG&E's service territory. On October 27, 2009, OG&E received notification from the DOE that its grant had been accepted by the DOE for the full requested amount of $130 million. Receipt of the grant monies is contingent upon successful negotiations with the DOE on final details of the award. OG&E expects to file an application with the OCC for requesting pre-approval for system-wide deployment of smart grid technology and a recovery rider, including a credit for the Smart Grid grant during the first quarter of 2010. Separately, on November 30, 2009, OG&E requested a grant with a 50 percent match of up to $5 million for a variety of types of smart grid training for OG&E's workforce. Recipients of the grant are expected to be announced in the first quarter of 2010.

Tallgrass Joint Venture

In July 2008, Tallgrass was formed to construct high-capacity transmission line projects. The Company owns 50 percent of Tallgrass. Tallgrass is intended to allow the participating companies to lead development of renewable wind by sharing capital costs associated with transmission construction. The Tallgrass projects are subject to creation by the SPP of a cost allocation method that would spread the total cost across the SPP region. OGE Energy is uncertain as to the timing of when the cost allocation method will be developed and approved. OGE Energy filed an application with the FERC in October 2008 for cost recovery of these projects subject to SPP and FERC approval for these projects. On December 2, 2008, the FERC granted Tallgrass' request for transmission rate incentives for the initial projects, established a base ROE for initial projects, approved certain accounting treatments for the initial projects and set the formula rate and accompanying protocols for hearing and settlement discussions. Tallgrass' initial projects could include 765 kV lines from Woodward 120 miles northwest to Guymon in the Oklahoma Panhandle and from Woodward 50 miles north to the Kansas border. An SPP study estimates the cost for the two projects if constructed as 765 kV lines to be approximately $500 million, of which OGE Energy's portion would be approximately $250 million. The capital expenditures related to the Tallgrass projects discussed above are excluded from the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements." The SPP continues to review the initial Tallgrass projects and has not made a final determination whether these projects should be built. The SPP is reviewing these projects as a portion of the list of "Priority Projects" and the SPP is expected to make decisions on these projects as to timing and voltage in the second quarter of 2010. If the SPP determines that the above 765 kV projects should be 345 kV projects, these projects are expected to be completed by OG&E. In December 2009, the Tallgrass agreement was amended between the joint venture owners to expand the joint venture from the two potential 765kV projects discussed above to also include any potential 765 kV projects in Oklahoma that any subsidiary of the joint venture partners has the right to construct. The period of the agreement was established for seven years unless earlier terminated via the conditions precedent, which expire in December of 2011.

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

On July 20, 2009, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2008 fuel adjustment clause. On September 18, 2009, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. On February 2, 2010, a procedural schedule was established in this matter with a hearing scheduled for May 26, 2010.

Enogex FERC Section 311 2007 Rate Case

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

On November 13, 2007, one of the protesting intervenors filed to consolidate the Enogex 2007 rate case with a separate Enogex application pending before the FERC allowing Enogex to lease firm capacity to MEP and with separate applications filed by MEP with the FERC for a certificate to construct and operate the new MEP pipeline and to lease firm capacity from Enogex. Enogex and MEP separately opposed this intervenor's protests and assertions in its initial and subsequent pleadings. On July 25, 2008, the FERC issued an order approving the MEP project including the approval of a limited jurisdiction certificate authorizing the Enogex lease agreement with MEP denying the request for consolidation and rejecting all claims raised by protestors regarding the lease agreement. Accordingly, Enogex proceeded with the construction of facilities necessary to implement this service. On August 25, 2008, the same protestor sought rehearing which the FERC denied. Enogex commenced service to MEP under the lease agreement on June 1, 2009. On July 16, 2009, the protestor filed, with the United States Court of Appeals for the District of Columbia Circuit, a petition for review of the FERC's orders approving the MEP construction and the MEP lease of capacity from Enogex requesting that such orders be modified or set aside on the grounds that they are arbitrary, capricious and contrary to law. The petitioner, the FERC and intervening parties have been given an opportunity to brief the issues. Enogex expects to participate in the filing of a joint intervenors' brief in support of the FERC's order in this matter, which final briefing is scheduled to be completed in the third quarter of 2010.

Enogex FERC Section 311 2009 Rate Case

On March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for its new firm East Zone Section 311 transportation service and to revise the rates for its existing East and West Zone interruptible Section 311 transportation service. In anticipation of offering this new service, Enogex had filed with the FERC, as required by the FERC's regulations, a revised Statement of Operating Conditions ("SOC") Applicable to Transportation Services to describe the terms, conditions and operating arrangements for the new service. Enogex made the SOC filing on February 27, 2009.

Enogex began offering firm East Zone Section 311 transportation service on April 1, 2009. The revised East and West Zone zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for the firm East Zone Section 311 transportation service and the increase in the rates for East and West Zone and interruptible Section 311 service are being collected, subject to refund, pending the FERC approval of the proposed rates. A number of parties intervened in both the rate case and the SOC filing and some additionally filed protests. Enogex filed answers to the interventions and protests in both matters. The FERC Staff served data requests on Enogex seeking additional information regarding various aspects of the filing and Enogex has submitted responses. On August 19, 2009, the FERC issued an order extending the time for action until it can make a determination whether Enogex's rates are fair and equitable or until the FERC determines that formal proceedings are necessary. The August 19, 2009 order also directed the FERC Staff to report to the FERC by December 29, 2009 on the status of settlement negotiations. On January 4, 2010, the FERC Staff submitted its initial settlement offer ("Offer") proposing various adjustments to Enogex's filed cost of service. Comments in response to the Offer were due on or before January 15, 2010. On January 14, 2010, Enogex asked the FERC Staff some clarifying questions regarding the Offer. Only Enogex and one intervenor filed comments on January 15, 2010, and each indicated that they were awaiting the FERC Staff's responses to the questions raised by Enogex before submitting substantive comments. The FERC Staff responded to the questions on January 20, 2010. Enogex anticipates that settlement discussions will continue.

Enogex 2010 Fuel Filing

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

On November 23, 2009, Enogex made its annual filing to establish the fixed fuel percentages for its East Zone and West Zone for calendar year 2010 (“2010 Fuel Year”). On December 9, 2009, the FERC issued a notice establishing December 18, 2009 as the due date for any interventions and protests. Several parties filed interventions. No protests were filed, but two intervenors reserved the right to do so, contingent upon the outcome of additional discussions with Enogex. On December 30, 2009, the FERC issued a letter order directing Enogex to submit certain additional information by January 13, 2010. Enogex submitted the information requested by the FERC and is continuing to discuss the filing with the intervenors.

North American Electric Reliability Corporation

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

Summary

The Energy Policy Act of 2005, the actions of the FERC and other factors are intended to increase competition in the electric industry. OG&E has taken steps in the past and intends to take appropriate steps in the future to remain a competitive supplier of electricity. While OG&E is supportive of competition, it believes that all electric suppliers must be required to compete on a fair and equitable basis and OG&E is advocating this position vigorously.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited the accompanying consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2009 and 2008, and the related consolidated statements of income, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of OGE Energy Corp. at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), OGE Energy Corp.'s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 17, 2010 expressed an unqualified opinion thereon.

As discussed in Note 1 to the consolidated financial statements, in 2009 the Company adopted Financial Accounting Standard No. 160, "Noncontrolling Interests in Consolidated Financial Statements" (ASC 810, Consolidation).

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 17, 2010

Supplementary Data

Interim Consolidated Financial Information (Unaudited)

In the opinion of the Company, the following quarterly information includes all adjustments, consisting of normal recurring adjustments, necessary to fairly present the Company's consolidated results of operations for such periods:

Quarter ended (*In millions, except per share data*)		March 31	June 30	September 30	December 31	Total
Operating revenues	**2009**	**$ 606.6**	**$ 644.1**	**$ 845.3**	**$ 773.7**	**$ 2,869.7**
	2008	994.7	1,135.7	1,254.3	686.0	4,070.7
Operating income	**2009**	**$ 52.0**	**$ 126.4**	**$ 229.7**	**$ 83.8**	**$ 491.9**
	2008	48.1	122.7	231.2	60.1 (A)	462.1
Net income	**2009**	**$ 17.6**	**$ 70.9**	**$ 137.5**	**$ 35.1**	**$ 261.1**
	2008	14.6	58.8	141.4	22.6 (A)	237.4
Net income attributable to OGE Energy	**2009**	**$ 16.8**	**$ 70.5**	**$ 136.8**	**$ 34.2**	**$ 258.3**
	2008	13.0	57.1	139.5	21.8 (A)	231.4
Basic earnings per average common share attributable to OGE Energy common shareholders (B)	**2009**	**$ 0.18**	**$ 0.73**	**$ 1.42**	**$ 0.35**	**$ 2.68**
	2008	0.14	0.62	1.51	0.23 (A)	2.50
Diluted earnings per average common share attributable to OGE Energy common shareholders (B)	**2009**	**$ 0.18**	**$ 0.72**	**$ 1.40**	**$ 0.35**	**$ 2.66**
	2008	0.14	0.62	1.50	0.23 (A)	2.49

(A) In the fourth quarter of 2008, OGE Energy wrote off transaction costs incurred related to the proposed joint venture between OGE Energy and Energy Transfer Partners, L.P. that was terminated and transaction costs associated with the formation of OGE Enogex Partners, L.P. of approximately $8.8 million.
(B) Due to the impact of dilution on the earnings per share ("EPS") calculation, the quarterly EPS amounts may not add to the total.

Dividends

COMMON STOCK

- Common quarterly dividends paid (as declared) in 2009 were $0.3550 each for the first three quarters of 2009 and was $0.3625 for the fourth quarter of 2009. Common quarterly dividends paid (as declared) in 2008 were $0.3475 each for the first three quarters of 2008 and was $0.3550 for the fourth quarter of 2008. Common quarterly dividends paid (as declared) in 2007 were $0.34 each for the first three quarters of 2007 and was $0.3475 for the fourth quarter of 2007.
- Present rate – $0.3625
- Payable 30th of January, April, July, and October

Item 9. Changes In and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission ("SEC") rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer ("CEO") and chief financial officer ("CFO"), allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the CEO and CFO, of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the CEO and CFO have concluded that the Company's disclosure controls and procedures are effective.

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

Management's Report on Internal Control Over Financial Reporting

The management of OGE Energy Corp. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the preparation and fair presentation of published financial statements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework. Based on our assessment, we believe that, as of December 31, 2009, the Company's internal control over financial reporting is effective based on those criteria.

The Company's independent auditors have issued an attestation report on the Company's internal control over financial reporting. This report appears on the following page.

/s/ Peter B. Delaney	/s/ Danny P. Harris
Peter B. Delaney, Chairman of the Board, President and Chief Executive Officer	Danny P. Harris, Senior Vice President and Chief Operating Officer
/s/ Sean Trauschke	/s/ Scott Forbes
Sean Trauschke, Vice President and Chief Financial Officer	Scott Forbes, Controller and Chief Accounting Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited OGE Energy Corp.'s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). OGE Energy Corp.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, OGE Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2009 and 2008, and the related consolidated statements of income, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2009 of OGE Energy Corp. and our report dated February 17, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 17, 2010

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

CODE OF ETHICS POLICY

The Company maintains a code of ethics for our chief executive officer and senior financial officers, including the chief financial officer and chie accounting officer, which is available for public viewing on the Company's web site address *www.oge.com* under the heading "Investor Relations" "Corporate Governance." The code of ethics will be provided, free of charge, upon request. The Company intends to satisfy the disclosure requirements under Section 5, Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the code of ethics by posting such information on its web site at the location specified above. The Company will also include in its proxy statement information regarding the Audit Committee financial expert

Item 11. Executive Compensation.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Item 14. Principal Accounting Fees and Services.

Items 10, 11, 12, 13 and 14 (other than Item 10 information regarding the Code of Ethics) are omitted pursuant to General Instruction G of Form 10-K, because the Company will file copies of a definitive proxy statement with the SEC on or about March 31, 2010. Such proxy statement is incorporated herein by reference. In accordance with General Instruction G of Form 10-K, the information required by Item 10 relating to Executive Officers has been included in Part I, Item 4, of this Annual Report on Form 10-K.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) 1. Financial Statements

The following consolidated financial statements and supplementary data are included in Part II, Item 8 of this Annual Report:

Ÿ Consolidated Statements of Income for the years ended December 31, 2009, 2008 and 2007

Ÿ Consolidated Balance Sheets at December 31, 2009 and 2008

Ÿ Consolidated Statements of Capitalization at December 31, 2009 and 2008

Ÿ Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2009, 2008 and 2007

Ÿ Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007

Ÿ Notes to Consolidated Financial Statements

Ÿ Report of Independent Registered Public Accounting Firm (Audit of Financial Statements)

Ÿ Management's Report on Internal Control Over Financial Reporting

Ÿ Report of Independent Registered Public Accounting Firm (Audit of Internal Control)

Supplementary Data

Ÿ Interim Consolidated Financial Information

2. Financial Statement Schedule (included in Part IV)	**Page**
Schedule II - Valuation and Qualifying Accounts	166

All other schedules have been omitted since the required information is not applicable or is not material, or because the information required is included in the respective consolidated financial statements or notes thereto.

3. Exhibits

Exhibit No.	**Description**
2.01	Purchase Agreement, dated as of May 14, 1999, by and between Tejas Gas, LLC and Enogex Inc. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 1999 (File No. 1-12579) and incorporated by reference herein)
2.02	Asset Purchase Agreement, dated as of August 18, 2003 by and between OG&E and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed August 20, 2003 (File No. 1-12579) and incorporated by reference herein)
2.03	Amendment No. 1 to Asset Purchase Agreement, dated as of October 22, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.04	Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.04 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.05	Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.05 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.06	Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.06 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.07	Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.07 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.08	Amendment No. 6 to Asset Purchase Agreement, dated as of March 12, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)
2.09	Amendment No. 7 to Asset Purchase Agreement, dated as of April 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)
2.10	Amendment No. 8 to Asset Purchase Agreement, dated as of May 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.11	Amendment No. 9 to Asset Purchase Agreement, dated as of June 2, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

2.12	Amendment No. 10 to Asset Purchase Agreement, dated as of June 17, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.13	Stock purchase agreement dated September 21, 2005 by and between Enogex Inc. and Atlas Pipeline Partners, L.P. (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed September 27, 2005 (File No. 1-12579) and incorporated by reference herein)
2.14	Asset purchase agreement dated March 30, 2006, by and between Enogex Gas Gathering, L.L.C. and Hiland Operating, Inc. (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed April 4, 2006 (File No. 1-12579) and incorporated by reference herein)
2.15	Purchase and Sale Agreement, dated as of January 21, 2008, entered into by and among Redbud Energy I, LLC, Redbud Energy II, LLC and Redbud Energy III, LLC and OG&E. (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)
2.16	Asset Purchase Agreement, dated as of January 21, 2008, entered into by and among OG&E, the Oklahoma Municipal Power Authority and the Grand River Dam Authority. (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)
3.01	Copy of Restated Certificate of Incorporation. (Filed as Exhibit 3.01 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)
3.02	Copy of Amended OGE Energy Corp. By-laws. (Filed as Exhibit 3.01 to OGE Energy's Form 8-K filed January 23, 2007 (File No. 1-12579) and incorporated by reference herein)
4.01	Trust Indenture dated October 1, 1995, from OG&E to Boatmen's First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to Registration Statement No. 33-61821 and incorporated by reference herein)
4.02	Supplemental Trust Indenture No. 1 dated October 16, 1995, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed October 24, 1995 (File No. 1-1097) and incorporated by reference herein)
4.03	Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed July 17, 1997 (File No. 1-1097) and incorporated by reference herein)
4.04	Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed April 16, 1998 (File No. 1-1097) and incorporated by reference herein)
4.05	Supplemental Indenture No. 4, dated as of October 15, 2000, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed October 20, 2000 (File No. 1-1097) and incorporated by reference herein)
4.06	Supplemental Indenture No. 5 dated as of October 24, 2001, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.06 to Registration Statement No. 333-104615 and incorporated by reference herein)
4.07	Supplemental Indenture No. 6 dated as of August 1, 2004, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed August 6, 2004 (File No 1-1097) and incorporated by reference herein)
4.08	Indenture dated as of November 1, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.01 to OGE Energy's Form 8-K filed November 12, 2004 (File No. 1-12579) and incorporated by

reference herein)

4.09	Supplemental Indenture No. 1 dated as of November 9, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.02 to OGE Energy's Form 8-K filed November 12, 2004 (File No. 1-12579) and incorporated by reference herein)
4.10	Supplemental Indenture No. 7 dated as of January 1, 2006 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.08 to OG&E's Form 8-K filed January 6, 2006 (File No. 1-1097) and incorporated by reference herein)
4.11	Supplemental Indenture No. 8 dated as of January 15, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed January 31, 2008 (File No. 1-1097) and incorporated by reference herein)
4.12	Supplemental Indenture No. 9 dated as of September 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed September 9, 2008 (File No. 1-1097) and incorporated by reference herein)
4.13	Supplemental Indenture No. 10 dated as of December 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed December 11, 2008 (File No. 1-1097) and incorporated by reference herein)
4.14	Issuing and Paying Agency Agreement dated as of June 15, 2009, by and between Enogex LLC and UMB Bank, N.A. (Filed as Exhibit 4.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2009 (File No. 1-12579) and incorporated by reference herein)
4.15	Issuing and Paying Agency Agreement dated as of November 15, 2009, by and between Enogex LLC and UMB Bank, N.A.
10.01*	The Company's 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy's Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)
10.02*	The Company's 2003 Stock Incentive Plan. (Filed as Annex A to OGE Energy's Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.03*	The Company's 2003 Annual Incentive Compensation Plan. (Filed as Annex B to OGE Energy's Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.04	Copy of Amended and Restated Rights Agreement, dated as of October 10, 2000 between OGE Energy Corp. and Chase Mellon Shareholder Services, LLC. (now BNY Mellon Shareowner Services), as Rights Agent. (Filed as Exhibit 4.1 to OGE Energy's Form 8-K filed November 1, 2000 (File No. 1-12579) and incorporated by reference herein)
10.05	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 6, 2009 (File No. 1-12579) and incorporated by reference herein)
10.06	Amended and Restated Facility Operating Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
10.07	Amended and Restated Ownership and Operation Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
10.08	Operating and Maintenance Agreement for the Transmission Assets of the McClain Generating Facility dated as of August 25, 2003 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.05 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference

herein)

10.09* Amendment No. 1 to the Company's 2003 Stock Incentive Plan. (Filed as Exhibit 10.23 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.10 Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement dated as of May 1, 2003 between OG&E and Enogex. [Confidential treatment has been requested for certain portions of this exhibit.] (Filed as Exhibit 10.24 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.11 Firm Transportation Service Agreement Rate Schedule FT dated as of December 1, 2004 between OGE Energy Resources, Inc. and Cheyenne Plains Gas Pipeline Company, L.L.C. (Filed as Exhibit 10.25 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.12* Form of Performance Unit Agreement under 2008 Stock Incentive Plan. (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q for the quarter ended March 31, 2009 (File No. 1-12579) and incorporated by reference herein)

10.13* Form of Split Dollar Agreement. (Filed as Exhibit 10.32 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.14 Credit agreement dated December 6, 2006, by and between the Company, the Lenders thereto, Wachovia Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, and The Royal Bank of Scotland plc, UBS Securities LLC and Union Bank of California, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed December 12, 2006 (File No. 1-12579) and incorporated by reference herein)

10.15 Credit agreement dated December 6, 2006, by and between OG&E, the Lenders thereto, Wachovia Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, and The Royal Bank of Scotland plc, Mizuho Corporate Bank and Union Bank of California, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 12, 2006 (File No. 1-12579) and incorporated by reference herein)

10.16* Amendment No. 1 to the Company's 1998 Stock Incentive Plan. (Filed as Exhibit 10.26 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)

10.17* Amendment No. 2 to the Company's 2003 Stock Incentive Plan. (Filed as Exhibit 10.27 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)

10.18 Capacity Lease Agreement dated as of December 11, 2006, by and between Enogex, Inc. and Midcontinent Express Pipeline LLC. [Confidential treatment has been requested for certain portions of this exhibit.] (Filed as Exhibit 10.30 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)

10.19 Ownership and Operating Agreement, dated as of January 21, 2008, entered into by and among OG&E, the Oklahoma Municipal Power Authority and the Grand River Dam Authority. (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)

10.20 Letter of extension for the Company's credit agreement dated November 11, 2007, by and between the Company and the Lenders thereto, related to the Company's credit agreement dated December 6, 2006. (Filed as Exhibit 10.35 to OGE Energy's Form 10-K for the year ended December 31, 2007 (File No. 1-12579) and incorporated by reference herein)

10.21 Letter of extension for OG&E's credit agreement dated November 11, 2007, by and between OG&E and the Lenders thereto, related to OG&E's credit agreement dated December 6, 2006. (Filed as Exhibit 10.36 to OGE Energy's Form 10-K for the year ended December 31, 2007 (File No. 1-12579) and incorporated by reference herein)

10.22 Credit Agreement dated as of April 1, 2008, by and among Enogex LLC, the Lenders thereto, Wachovia Bank, National Association, as Administrative Agent, The Royal Bank of Scotland plc, as Syndication Agent, and

JPMorgan Chase Bank, N.A, Mizuho Corporate Bank, LTD. and Union Bank of California, as Co-Documentation Agents. (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed April 7, 2008 (File No. 1-12579) and incorporated by reference herein)

10.23*	Amendment No. 1 to the Company's 2003 Annual Incentive Compensation Plan. (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.24*	OGE Energy Corp. Supplemental Executive Retirement Plan, as amended and restated. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.25*	OGE Energy Corp. Restoration of Retirement Income Plan, as amended and restated. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.26*	OGE Energy Corp. Deferred Compensation Plan, as amended and restated. (Filed as Exhibit 10.05 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.27*	Amendment No. 3 to the Company's 2003 Stock Incentive Plan. (Filed as Exhibit 10.06 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.28*	Amendment No. 2 to the Company's 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.29*	The Company's 2008 Stock Incentive Plan. (Filed as Annex A to OGE Energy's Proxy Statement for the 2008 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.30*	The Company's 2008 Annual Incentive Compensation Plan. (Filed as Annex B to OGE Energy's Proxy Statement for the 2008 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.31*	Form of Amended and Restated Change of Control Agreement with current officers of the Company. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2008 (File No. 1-12579) and incorporated by reference herein)
10.32*	Amended and Restated Change of Control Agreement with Peter B. Delaney. (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2008 (File No. 1-12579) and incorporated by reference herein)
10.33*	Form of Change of Control Agreement with future officers of the Company. (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2009 (File No. 1-12579) and incorporated by reference herein)
10.34*	Form of Restricted Stock Agreement under 2008 Stock Incentive Plan. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended September 30, 2008 (File No. 1-12579) and incorporated by reference herein)
10.35*	Directors' Compensation.
10.36*	Executive Officer Compensation.
10.37*	Employment Arrangement between the Company and Sean Trauschke, the Company's Chief Financial Officer. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2009 (File No. 1-12579) and incorporated by reference herein)
10.38*	Change of Control Arrangement between the Company and Sean Trauschke, the Company's Chief Financial Officer. (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed May 8, 2009 (File No. 1-12579) and incorporated by reference herein)

10.39	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's OU Spirit application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 2, 2009 (File No. 1-12579) and incorporated by reference herein)
10.40*	Amendment No. 1 to the Company's Restoration of Retirement Income Plan.
10.41*	Amendment No. 1 to the Company's Deferred Compensation Plan.
12.01	Calculation of Ratio of Earnings to Fixed Charges.
18.01	Letter from Ernst & Young LLP related to a change in accounting principle. (Filed as Exhibit 18.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
21.01	Subsidiaries of the Registrant.
23.01	Consent of Ernst & Young LLP.
24.01	Power of Attorney.
31.01	Certifications Pursuant to Rule 13a-15(e)/15d-15(e) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995.
99.02	Copy of OCC order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 30, 2009 (File No. 1-12579) and incorporated by reference herein)
99.03	Copy of APSC order with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed May 27, 2009 (File No. 1-12579) and incorporated by reference herein)
99.04	Copy of OCC order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's OU Spirit application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed October 21, 2009 (File No. 1-12579) and incorporated by reference herein)

* Represents executive compensation plans and arrangements.

OGE ENERGY CORP.

SCHEDULE II - Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
	(In millions)				
Year Ended December 31, 2007					
Reserve for Uncollectible Accounts	$ 4.4	$ 6.0	$ ---	$ 6.6 (A)	$ 3.8
Year Ended December 31, 2008					
Reserve for Uncollectible Accounts	$ 3.8	$ 5.0	$ ---	$ 5.6 (A)	$ 3.2
Year Ended December 31, 2009					
Reserve for Uncollectible Accounts	$ 3.2	$ 3.1	$ ---	$ 3.9 (A)	$ 2.4

(A) Uncollectible accounts receivable written off, net of recoveries.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, and State of Oklahoma on the 18th day of February, 2010.

OGE ENERGY CORP.
(Registrant)

By /s/ Peter B. Delaney
Peter B. Delaney
Chairman of the Board, President
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this Report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated.

Signature	Title	Date
/ s / Peter B. Delaney Peter B. Delaney	Principal Executive Officer and Director;	February 18, 2010
/ s / Sean Trauschke Sean Trauschke	Principal Financial Officer; and	February 18, 2010
/ s / Scott Forbes Scott Forbes	Principal Accounting Officer.	February 18, 2010
Wayne H. Brunetti	Director;	
Luke R. Corbett	Director;	
John D. Groendyke	Director;	
Kirk Humphreys	Director;	
Robert Kelley	Director;	
Linda P. Lambert	Director;	
Robert O. Lorenz	Director;	
Leroy C. Richie	Director; and	
J. D. Williams	Director.	
/ s / Peter B. Delaney By Peter B. Delaney (attorney-in-fact)		February 18, 2010

Exhibit 4.15

ISSUING AND PAYING AGENCY AGREEMENT

THIS ISSUING AND PAYING AGENCY AGREEMENT, dated as of November 15, 2009 (the "Agreement"), is made by and between ENOGEX LLC, a limited liability company organized under the laws of the State of Delaware (the "Issuer"), and UMB BANK, N.A., a national banking association duly organized and existing under the laws of the United States, as issuing and paying agent (the "Issuing Agent"). Terms used and not defined herein but defined in the Notes (as hereinafter defined) have the meanings set forth in the Notes.

WITNESSETH:

SECTION 1. Appointment of Agent. The Issuer proposes to issue its 6.25% Senior Notes due 2020 (the "Notes"), initially in the aggregate principal amount of $250,000,000. As provided in Section 11 below, the series of Notes may be reopened and additional notes in excess of $250,000,000 may be issued. The Issuer and J.P. Morgan Securities Inc., Mitsubishi UFJ Securities (USA), Inc., Wells Fargo Securities, LLC, BNY Mellon Capital Markets, LLC, U.S. Bancorp Investments, Inc., KeyBanc Capital Markets Inc. and BOSC, Inc. (collectively, the "Initial Purchasers") have entered into a Purchase Agreement dated as of November 10, 2009, relating to the sale and purchase of the Notes. The Issuer hereby appoints the Issuing Agent to act, on the terms and conditions specified herein, as issuing and paying agent for the Notes.

SECTION 2. Note Form; Terms; Execution. The Notes shall be in substantially the form of Exhibit A hereto. The Notes shall be in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof and shall be redeemable by the Issuer prior to maturity as provided in the form of Note and shall bear interest as provided in the form of Note. Each Note shall be executed by the manual or facsimile signature of an Authorized Representative (as defined in Section 3 hereof) of the Issuer and shall be authenticated by the Issuing Agent.

SECTION 3. Authorized Representatives. From time to time, the Issuer will furnish the Issuing Agent with a certificate of the Issuer certifying the incumbency and specimen signatures of the Issuer's officers authorized to execute Notes on behalf of the Issuer by manual or facsimile signature (an "Authorized Representative"). Until the Issuing Agent receives a subsequent incumbency certificate of the Issuer, the Issuing Agent shall be entitled to rely on the last such certificate delivered to it for purposes of determining the Authorized Representatives. The Issuing Agent shall have no responsibility to the Issuer to determine by whom or by what means a facsimile signature may have been affixed on the Notes, or to determine whether any facsimile or manual signature is genuine. Any Note bearing the manual or facsimile signature of a person who is an Authorized Representative on the date such signature is affixed shall bind the Issuer after the completion and authentication thereof by the Issuing Agent, notwithstanding that such person shall have ceased to hold office on the date such Note is completed, authenticated and delivered by the Issuing Agent.

SECTION 4. Issuance Instructions; Completion, Authentication and Delivery of Notes. Prior to the original issuance of the Notes, the Authorized Representative shall give written issuance instructions (the "Issuance Instructions") to the Issuing Agent directing that the Issuing Agent issue and authenticate the Notes. The Issuing Agent shall have no duty to issue Notes in the absence of the Issuance Instructions. The Issuance Instructions shall include the: (a) names and addresses of the persons in whose name the Note shall be registered (each, a "Registered Holder") and the addresses for payment, if different; (b) taxpayer identification number of each Registered Holder; (c) Principal Amount, Stated Maturity Date, Interest Rate, Original Issue Date and delivery instructions. The Issuing Agent shall deliver the Notes on the Original Issuance Date in accordance with the Issuance Instructions.

SECTION 5. Issuer's Representations and Warranties. The Issuance Instructions shall constitute the Issuer's representation and warranty to the Issuing Agent that the issuance and delivery of the Notes have been duly and validly authorized by the Issuer and that the Notes, when completed, authenticated and delivered pursuant hereto, will constitute the legal, valid and binding obligations of the Issuer.

SECTION 6. Payment of Note Interest; Interest Payment Dates; Record Dates; Interest Rights.

(a) Interest payments on the Notes will be made semiannually on March 15 and September 15 of each year, commencing March 15, 2010, and upon redemption or at maturity. All such interest payments (other than interest due upon redemption or at maturity) will be made to the persons who are the Registered Holders at the close of business on the fifteenth day (whether or not a Business Day) immediately preceding each such Interest Payment Date (each a "Regular Record Date"), *provided*, *however*, that interest payable upon redemption or at maturity will be payable to the person to whom the principal is payable. Notwithstanding the foregoing, if the Original Issue Date or date of transfer, exchange or substitution of any Note occurs either on an Interest Payment Date or between a Regular Record Date and the next succeeding Interest Payment Date, the first payment of interest on any such Note will be made on the Interest Payment Date next following the next succeeding Regular Record Date to the person who is the Registered Holder on such next succeeding Regular Record Date. If an Interest Payment Date, maturity or redemption date would fall on a day that is not a Business Day, the Interest Payment Date, maturity or redemption date will be the next succeeding Business Day. Interest on a Note will accrue from, and including, the Original Issue Date or from, and including, the most recent date to which interest has been paid or duly provided for with respect to that Note. Interest on the Notes will be calculated on the basis of a 360-day year of twelve 30-day months.

Payment of principal of, and premium, if any, and interest on any Notes issued in the form of Global Notes (as defined below) will be made by the Issuer through the Issuing Agent to The Depository Trust Company ("DTC") or any successor securities depositary. Interest on any Notes that are in certificated form will be paid by check mailed to the Registered Holder at that Registered Holder's address as it appears in the register for the Notes maintained by the Issuing Agent; provided, however, a Registered Holder of $10,000,000 or more in aggregate principal amount of Notes will be entitled to receive payments of interest by wire transfer to a bank within the continental United States, if appropriate wire transfer instructions have been received by the Issuing Agent on or prior to the applicable Regular Record Date. Such wire instructions, upon receipt by the Issuing Agent, shall remain in effect until revoked by such Registered Holder. The principal, interest at maturity and premium, if any, on Notes in certificated form will be payable in immediately available funds at the office of the Issuing Agent upon presentation of the Notes. If required by law, the Issuing Agent will withhold any taxes or other governmental charges on any payment made in connection with the Notes.

(b) Any interest on any Note which is payable, but is not punctually paid or duly provided for, on any Interest Payment Date ("Defaulted Interest") shall forthwith cease to be payable to the person who is the Registered Holder on the relevant Regular Record Date by virtue of having been such Registered Holder, and such Defaulted Interest may be paid by the Issuer, at its election in each case, as provided in clause (i) or (ii) below:

(i) The Issuer may elect to make payment of any Defaulted Interest to the persons who are the Registered Holders of the Notes to which the Defaulted Interest relates ("Defaulted Notes") (or their respective predecessor Notes) at the close of business on a special record date for the payment of such Defaulted Interest, which special record date shall be fixed in the following manner. The Issuer shall notify the Issuing Agent in writing of the amount of Defaulted Interest proposed to be paid on each of the Defaulted Notes and the date of the proposed payment, and at the same time the Issuer shall deposit with the Issuing Agent an amount of money equal to the aggregate amount proposed to be paid in respect of such Defaulted Interest or shall make arrangements satisfactory to the Issuing Agent for such deposit prior to the date of the proposed payment, such money when deposited to be held in trust for the benefit of those entitled to such Defaulted Interest as in this clause provided. Thereupon the Issuing Agent shall fix a special record date for the payment of such Defaulted Interest which shall be not more than 15 days and not less than 10 days prior to the date of the proposed payment and not less than 10 days after the receipt by the Issuing Agent of the notice of the proposed payment. The Issuing Agent shall promptly notify the Issuer of such special record date and, in the name and at the expense of the Issuer, shall cause notice of the proposed payment of such Defaulted Interest and the special record date therefor to be mailed, first-class postage prepaid, to each Registered Holder of Defaulted Notes as of the special record date at the address as it appears in the Note Register, not less than 10 days prior to such special record date. Notice of the proposed payment of such Defaulted Interest and the special record date therefor having been so mailed, such Defaulted Interest shall be paid to those in whose names the Defaulted Notes (or their respective predecessor Notes) are registered at the close of business on such special record date and shall no longer be payable pursuant to following clause (ii).

(ii) The Issuer may make payment of any Defaulted Interest on the Defaulted Notes in any other lawful manner not inconsistent with the requirements of any securities exchange which maintains a system for the trading of restricted securities and through which the Notes are so traded, and upon such notice as may be required by such exchange, if, after notice given by the Issuer to the Issuing Agent of the proposed payment pursuant to this clause, such manner of payment shall be deemed practicable by the Issuing Agent. Subject to the foregoing provisions of this Section, each Note authenticated and delivered under this Agreement upon registration of transfer or in exchange for or in lieu of any other Note shall carry the rights to interest accrued and unpaid, and to accrue, which were carried by such other Note.

SECTION 7. Payment of Note Principal. The Issuing Agent will pay to the Registered Holder in immediately available funds the principal amount of each Note on the redemption date, if any, or at maturity, together with accrued interest, if any, and premium, if any, due upon redemption or at maturity, only upon presentation and surrender of such Note on or after the redemption date or maturity date thereof, as the case may be, at the offices of the Issuing Agent located at the address listed in Section 23(b)(ii) hereof, or at such other address of the Issuing Agent or the office or agency of such other paying agent as the Issuer shall designate in the Borough of Manhattan, New York City, in writing to the Registered Holder of such Note. The Issuing Agent will forthwith cancel each such Note and promptly forward same in due course to the Issuer.

SECTION 8. Other Information Regarding the Notes. On any day on which Notes are issued, redeemed or mature, the Issuing Agent shall prepare and forward to the Issuer as of the close of business on such day a written statement indicating by Note number and principal amount of the Notes issued on such day and the aggregate principal amount of the Notes outstanding at the close of business on such day.

SECTION 9. Deposit of Funds. The Issuer shall deposit with the Issuing Agent not later than 10:00 a.m. New York City time on each Interest Payment Date funds available for payment on such Interest Payment Date in an amount sufficient to pay all interest due on the Notes on such Interest Payment Date and shall deposit with the Issuing Agent not later than 10:00 a.m. New York City time on each redemption date or maturity date of any Note funds available for payment on such Interest Payment Date in an amount sufficient to pay the principal of, premium, if any, and accrued interest, if any, on any such Note to, but excluding, the redemption date or maturity date, as the case may be. If there is deposited with the Issuing and Paying Agent as trust funds, for the purpose hereinafter stated, an amount, in cash or in U.S. Government Securities sufficient to pay and discharge the principal of and premium and interest, if any, on the Notes, as and when the same become due and payable, including upon any redemption prior to maturity, the Issuer will be deemed to have satisfied and discharged the Notes. Notwithstanding the foregoing, if the Notes are to be redeemed prior to their maturity as contemplated by Section 10 hereof, such Notes will not be deemed satisfied and discharged until such Notes have been irrevocably called or designated for redemption on a date when such Notes may be called for redemption and proper notice of redemption has been given in accordance with the terms of the Notes or the Issuer has given the Issuing and Paying Agent irrevocable instructions to give such notice of redemption.

SECTION 10. Optional Redemption. The Notes shall be subject to redemption at the option of the Issuer as provided in the form of Note attached hereto as Exhibit A. In the event that the Issuer elects to redeem Notes, in whole or in part, the Issuer shall give written notice to the Issuing Agent of the principal amount of Notes to be so redeemed not less than 45 days or more than 60 days prior to the redemption date, which notice shall also specify the redemption date and applicable redemption price or the method of determining the same. The Issuing Agent shall cause notice of redemption to be given not less than 30 or more than 60 days prior to the redemption date in the name, and at the expense, of the Issuer in the manner provided in the Note. Whenever less than all the Notes outstanding are to be redeemed, the Notes to be so redeemed shall be selected by the Issuing Agent, by lot or in any usual manner approved by it.

SECTION 11. Reopening of Notes. The Notes may be reopened and additional Notes may be issued in excess of the limitation set forth in Section 1, *provided* that such additional Notes will contain the same terms (including the maturity date and interest payment terms) as the other Notes. Any such additional Notes, together with the other Notes, shall constitute a single series for purposes of this Agreement.

SECTION 12. Note Register; Registration, Transfer, Exchange; Persons Deemed Owners.

(a) It is understood that the Note Register (as hereinafter defined) shall be maintained by such method as the Issuer and the Issuing Agent shall mutually agree. The term "Note Register" shall mean the definitive record in which shall be recorded the names, addresses, addresses for payment and taxpayer identification numbers of the Registered Holders, the Note numbers and Original Issue Date thereof and details with respect to the issuance, transfer and exchange of Notes, as appropriate.

(b) Upon the presentation of a Note for registration of transfer, the Issuing Agent shall register the transfer of such Note if such Note is to be transferred:

(i) to the Issuer or any of the Issuer's subsidiaries;

(ii) for so long as the Notes are eligible for resale pursuant to Rule 144A ("Rule 144A") under the Securities Act of 1933, as amended (the "Securities Act"), to a person whom the seller reasonably believes is a "qualified institutional buyer" (as defined in Rule 144A) that purchases for its own account or for the account of a qualified institutional buyer to which notice is given that the transfer is being made in reliance on Rule 144A;

(iii) pursuant to offers and sales to persons other than "U.S. persons," as that term is defined in Rule 902 of Regulation S under the Securities Act ("Regulation S"), that occur outside the United States in accordance with Regulation S;

(iv) pursuant to a registration statement that has been declared effective under the Securities Act; or

(v) pursuant to any other available exemption from the registration requirements of the Securities Act,

subject, in each of the foregoing cases, to any requirement of law that the disposition of property or the property of such investor account or accounts be at all times within its or their control and, in each case, in compliance with applicable securities laws of any U.S. state or any other applicable jurisdiction. The Issuer and the Issuing Agent, as the case may be, reserve the right prior to any offer, sale or other transfer of such a Note described in clause (ii), (iii) or (v) above to require the delivery of an opinion of counsel, certifications and/or other information satisfactory to the Issuer and the Issuing Agent, as the case may be, including, among other things, requiring the holder and the prospective purchaser or transferee to complete the Certificate of Transfer on the reverse of such Note or a duly completed Bond Power substantially in the form attached hereto as Exhibit B (the "Bond Power") to advise the Issuing Agent of the basis for such transfer and the availability of the exemption from registration provided thereby; provided that a Certificate of Transfer or Bond Power shall not be required in the case of any Note in certificated form from which the restrictive legend originally set forth on the face thereof (or on the face of one or more predecessor Notes) has been removed with the consent of the Issuer in accordance with the procedures set forth in this Agreement. In registering the transfer of any Notes pursuant to this

Section 12(b) or Section 12(h), the Issuing Agent shall be entitled to rely without further investigation on a duly completed Bond Power or such other certificate or instrument of transfer that the Issuer has advised the Issuing Agent is acceptable to the Issuer.

With respect to any transfer of interests in a Note described in clause (iii) above on or prior to the 40th day after the later of the commencement of the offering of the Notes and the date of the initial issuance of the Notes, if the Note is being transferred to a holder described in clause (ii) above, the Issuing Agent will require written certification from the transferee or transferor, as the case may be, (in the form of the Bond Power) to the effect that (i) such transferee is purchasing the Notes for its own account or for accounts as to which it exercises sole investment discretion and that it and, if applicable, each account is a qualified institutional buyer within the meaning of Rule 144A, in each case, in a transaction meeting the requirements of Rule 144A and in accordance with any applicable securities laws of any state of the United States or any other jurisdiction or (ii) the transferor did not purchase the Notes as part of the initial distribution thereof and the transfer is being effected pursuant to and in accordance with an applicable exemption from the registration requirements of the Securities Act and the transferor has delivered to the Issuing Agent such additional evidence that the Issuer or the Issuing Agent, as applicable, may require as to compliance with such available exemption.

With respect to any transfer of interests in a Note described in clause (ii) above at any time, if the Notes is being transferred to a holder described in clause (iii) above, the Issuing Agent will require written certification from the transferee or transferor, as the case may be, (in the form of the Bond Power) to the effect that such transferee is not a U.S. person within the meaning of Rule 902 of Regulation S and that it is acquiring the Note in a transaction or transactions taking place outside the United States in accordance with Regulation S.

(c) In connection with the issuance of Notes arising from a transfer, the Original Issue Date of the Note shall be the same date as the Original Issue Date of the Note being transferred.

(d) In connection with any registration of transfer of Notes, the Issuer and the Issuing Agent may require payment of a sum sufficient to cover any applicable tax or other governmental charge.

(e) Prior to due presentment of a Note for registration of transfer, the Issuer and the Issuing Agent may deem and treat the Registered Holder of any Note as the absolute owner of such Note for the purpose of receiving payment of the principal of, premium, if any, and interest on such Note and for all other purposes whatsoever, whether or not such Note or the interest thereon shall be overdue, and neither the Issuer nor the Issuing Agent, except as provided in this Section 12, shall be affected by notice to the contrary.

(f) Each Note presented for registration of transfer shall be duly endorsed or be accompanied by an appropriate written instrument of transfer.

(g) Upon surrender for registration of transfer of any Note and satisfaction of the requirements of this Section 12, the Issuing Agent shall complete, authenticate and deliver, in the name of the designated transferee or transferees, one or more new registered Notes of any authorized denominations, of a like aggregate principal amount, bearing a number not contemporaneously outstanding and containing identical terms and provisions.

(h) Subject to the requirements of Section 12(b) hereof, at the option of any Registered Holder, Notes may be exchanged for other Notes containing identical terms and provisions, in any authorized denominations, and of a like aggregate principal amount, upon surrender of the Notes to be exchanged to the Issuing Agent, *provided* that there is no obligation to exchange or register the transfer of any Note during the period of 15 days immediately preceding the date of first giving any notice of redemption of Notes. Whenever any Notes are so surrendered for exchange, the Issuing Agent shall complete, authenticate and deliver the Notes that the Registered Holder making the exchange is entitled to receive.

SECTION 13. Mutilated, Destroyed, Lost, or Stolen Notes. In case any Note shall become mutilated or destroyed, lost or stolen, the Issuer in its discretion may execute and upon its request the Issuing Agent shall complete, authenticate and make available for delivery a Note, having the same terms and provisions and a number not contemporaneously outstanding, payable in the same principal amount, of like tenor, and dated the same Original Issue Date in exchange and substitution for the mutilated Note or in lieu of and substitution for the Note destroyed, lost or stolen. The applicant for a substituted Note shall furnish to the Issuer and the Issuing Agent such security or indemnity as may be required by them to hold each of them harmless, and, in every case of destruction, loss or theft, the applicant shall also furnish to the Issuer and the Issuing Agent evidence to their satisfaction of the destruction, loss or theft of such Note and of the ownership thereof. The Issuing Agent shall complete and authenticate any such substituted Note and deliver the same upon the written request or authorization of any Authorized Representative. Upon the issuance of any substituted Note, the Issuer and the Issuing Agent may require the Registered Holder of such Note to pay a sum sufficient to cover any fees and expenses associated therewith. In case any Note which has matured or will mature or will be redeemed within 30 days shall become mutilated or be destroyed, lost or stolen, the Issuer, instead of issuing a substitute Note, may pay or authorize the payment of the same (without surrender thereof except in the case of a mutilated Note) upon compliance by the Registered Holder with the provisions of this Section, as hereinabove set forth. The Issuing Agent shall record on the Note Register the cancellation of any original Notes (whether or not physically surrendered to the Issuing Agent) and the reissue of Notes in substitution therefor due to mutilation, destruction, loss or theft.

SECTION 14. Application of Funds; Return of Unclaimed Funds. Until used or applied as herein provided, all funds received by the Issuing Agent hereunder shall be held for the purposes for which they were received but need not be segregated from other funds except to the extent required by law. The Issuing Agent shall be under no liability for interest on any funds received by it hereunder except as otherwise agreed with the Issuer. Any funds deposited with the Issuing Agent and remaining unclaimed at the end of two years after the date upon which the last payment of the principal of, premium, if any, or interest on any Note to which such deposit relates shall have become due and payable, shall be repaid to the Issuer by the Issuing Agent at the Issuer's written request, and the Holder of any Note to which such deposit relates entitled to receive payment thereof shall thereafter look only to the Issuer for the payment thereof and all liability of the Issuing Agent with respect to such funds shall thereupon cease.

SECTION 15. Global Notes.

(a) If specified in the Issuance Instructions, except as provided in subsections (c) and (g) below, the holder of all of the Notes to be issued pursuant to such Issuance Instructions shall be DTC and such Notes shall be registered in the name of Cede & Co., as nominee for DTC.

(b) Such Notes shall initially be issued in the form of one or more authenticated, fully registered certificates in the name of Cede & Co. (the "Global Notes"), which shall represent, and shall be denominated in an amount equal to, the aggregate principal amount of such of the Notes as shall be specified therein. Upon initial issuance, the Initial Purchasers shall deliver the Notes in book-entry form only through the facilities of DTC and its participants, including its participants Euroclear Bank S.A./N.V., as operator of the Euroclear System, and Clearstream Banking, société anonyme, and the ownership of such Notes shall be registered in the Note Register in the name of Cede & Co., as nominee of DTC. So long as Notes are evidenced by one or more Global Notes, the Issuing Agent and the Issuer may treat DTC (or its nominee) as the sole and exclusive holder of such Notes registered in its name for the purposes of payment of the principal of, premium, if any, and interest on such Notes or portion thereof to be redeemed, and of giving any notice permitted or required to be given to holders of such Notes and neither the Issuing Agent nor the Issuer shall be affected by any notice to the contrary. Neither the Issuing Agent nor the Issuer shall have any responsibility or obligation to any of DTC's participants (each a "Participant"), any person claiming a beneficial ownership in such Notes under or through DTC or any Participant (each a "Beneficial Owner"), or any other person which is not shown on the Note Register as being a holder, with respect to the accuracy of any records maintained by DTC or any Participant; the payment of DTC or any Participant of any amount in respect of the principal of, premium, if any, or interest on such Notes; any notice which is permitted or required to be given to holders of such Notes; the selection by DTC or any Participant of any person to receive payment in the event of a partial redemption of such Notes; any notice which is permitted or required to be given to holders of such Notes; the selection by DTC or any Participant of any person to receive payment in the event of a partial redemption of such Notes; or any consent given or other action taken by DTC as holder of such Notes. The Issuing Agent shall pay all principal of, premium, if any, and interest on such Notes registered in the name of Cede & Co. only to or "upon the order of" DTC (as that term is used in the Uniform Commercial Code as adopted in New York), and all such payments shall be valid and effective to fully satisfy and discharge the Issuer's obligations with respect to the principal of, premium, if any, and interest on such Notes to the extent of the sum or sums so paid. Except as otherwise provided in subsections (c) and (g) of Section 15 below, no person other than DTC shall receive authenticated Note certificates evidencing the obligation of the Issuer to make payments of principal of, premium, if any, and interest on such Notes. Upon delivery by DTC to the Issuing Agent of written notice to the effect that DTC has determined to substitute a new nominee in place of Cede & Co., and subject to the other provisions of this Agreement with respect to transfers of Notes, the word "Cede & Co." in this Agreement shall refer to such new nominee of DTC.

(c) Any Global Note shall be exchangeable for Notes in certificated form registered in the names of Participants and/or Beneficial Owners if, but only if, (i) DTC notifies the Issuer that it is unwilling or unable to continue as depositary for such Notes and a successor depository is not appointed by the Issuer within 90 days of such notice, or (ii) there shall have occurred and be continuing a default or an event that with notice or passage of time, or both, would constitute a default with respect to the Global Notes and the Issuing Agent has received a request from DTC to issue Notes in certificated form. In any such event, the Issuing Agent shall issue, transfer and exchange Note certificates as requested by DTC in appropriate amounts pursuant to this Agreement. The Issuer shall pay all costs in connection with the production, execution and delivery of such Note certificates. If Note certificates are issued, the provisions of this Agreement shall apply to, among other things, the transfer and exchange of such certificates and the method of payment of principal of, premium, if any, and interest on such certificates.

(d) Notwithstanding any other provision of this Agreement to the contrary, so long as any Notes are evidenced by one or more Global Notes, registered in the name of Cede & Co., as nominee of DTC, all payments with respect to the principal of, premium, if any, and interest on such Notes and all notices with respect to such Notes shall be made and given, respectively, to DTC as provided in the representation letter relating to the Notes among DTC, the Issuing Agent and the Issuer. The Issuing Agent is hereby authorized and directed to comply with all terms of the representation letter.

(e) In connection with any notice or other communication to be provided to the holders of such Notes by the Issuer or the Issuing Agent with respect to any consent or other action to be taken by the holders of such Notes, the Issuer or the Issuing Agent, as the case may be, shall seek to establish a record date for such consent or other action and give DTC notice of such record date not less than 15 calendar days in advance of such record date to the extent possible. Such notice to DTC shall be given only when DTC is the sole holder of the Notes.

(f) Neither the Issuer nor the Issuing Agent will have any responsibility or obligations to the Participants or the Beneficial Owners with respect to (i) the accuracy of any records maintained by DTC or any Participant, (ii) the payment by DTC or any Participant of any amount due to any Beneficial Owner in respect of the principal of, premium, if any, or interest on the Notes, (iii) the delivery by DTC or any Participant of any notice to any Beneficial Owner, (iv) the selection of the Beneficial Owners to receive payment in the event of any partial redemption of the Notes, or (v) any consent given or other action taken by DTC as a holder of the Notes.

So long as Cede & Co. is the Registered Holder of the Notes as nominee of DTC, references herein to the Notes or Registered Holders of the Notes shall mean Cede & Co. and shall not mean the Beneficial Owners of the Notes nor DTC Participants.

(g) No Global Note may be transferred except as a whole by DTC to a nominee of DTC or by a nominee of DTC to DTC or another nominee of DTC or by DTC or any such nominee to a successor of DTC or a nominee of such successor.

(h) Upon the termination of the services of DTC with respect to any Global Note pursuant to subsection (c) of this Section 15 after which no substitute book-entry depository is appointed, such Global Notes shall be registered in whatever name or names holders transferring or exchanging such Global Notes shall designate in accordance with the provisions of this Agreement.

SECTION 16. Liability. Neither the Issuing Agent nor its officers or employees shall be liable to the Issuer for any act or omission hereunder except in the case of the Issuing Agent's negligence or willful misconduct. The duties and obligations of the Issuing Agent, its officers and employees shall be determined by the express provisions of this Agreement and they shall not be liable except for the performance of such duties and obligations as are specifically set forth herein and no implied covenants shall be read into this Agreement against them. The Issuing Agent may consult with counsel of its selection and shall be fully protected in any action taken in good faith in accordance with the advice of counsel. Neither the Issuing Agent nor its officers or employees shall be required to ascertain whether any sale of Notes (or any amendment or termination of this Agreement) has been duly authorized (*provided* that the Issuing Agent in good faith has determined in accordance with Section 3 hereof that the facsimile or manual signature of an Authorized Representative or any person who has been designated by an Authorized Representative in writing to the Issuing Agent resembles the specimen signature filed with the Issuing Agent) or is in compliance with any other agreement to which the Issuer is a party (whether or not the Issuing Agent is also a party to such other agreement). The Issuing Agent shall not be required to, and shall not, expend or risk any of its own funds or otherwise incur any financial liability in the performance of any of its duties hereunder.

SECTION 17. Indemnification. The Issuer agrees to indemnify and hold harmless the Issuing Agent, its directors, officers, employees and agents from and against any and all liabilities (including liability for penalties), losses, claims, damages, actions, suits, judgments, demands, costs and expenses (including reasonable legal fees and expenses of counsel of its selection) relating to or arising out of or in connection with its or their performance under this Agreement, except to the extent that they are caused by the negligence or willful misconduct of the Issuing Agent, its directors, officers, employees or agents; *provided*, *however*, that if any such action or suit shall be commenced against, or any such claim or demand be assessed against the Issuing Agent in respect of which the Issuing Agent or any of its directors, officers, employees or agents proposes to demand indemnification, the Issuer shall be notified to that effect with reasonable promptness and shall have the right to assume the entire control of the defense, compromise or settlement thereof, including employment of counsel (*provided* that the Issuing Agent shall have the right to consent in advance to the counsel so employed, such consent not to be unreasonably withheld, and *provided further* that the Issuer shall consult in good faith with the Issuing Agent from time to time in connection with such action or suit) and in connection therewith, the Issuing Agent and its directors, officers, employees and agents shall cooperate fully to make available to the Issuer all pertinent information under its and their control. The foregoing indemnity includes, but is not limited to, any action taken or omitted in good faith within the scope of this Agreement upon telephonic, telecopier or other electronically transmitted instructions, if authorized herein, received from, or reasonably believed by the Issuing Agent in good faith to have been given by, an Authorized Representative. This indemnity shall survive the resignation or removal of the Issuing Agent and the satisfaction or termination of this Agreement.

SECTION 18. Electronic System Timesharing. It is understood that any electronic timesharing services which may be utilized by the Issuer and the Issuing Agent in the issuance of Notes and maintenance of the Note Register may be furnished to the Issuing Agent by a third party provider. If such third party provider has granted permission to the Issuing Agent to allow its clients to use such timesharing services, and in consideration for such permission, it is understood and agreed that such services will be supplied to such clients "as is", without warranty by the third party provider or the Issuing Agent, then the Issuer hereby waives any claims it may have against such third party provider.

SECTION 19. Compensation of the Issuing Agent. The Issuer agrees to pay the compensation of the Issuing Agent at such rates as shall be agreed upon from time to time in writing and to reimburse the Issuing Agent for its reasonable out-of-pocket expenses (including reasonable legal fees and expenses), disbursements and advances incurred or made in connection with the Issuing Agent's execution and performance of this Agreement. The obligations of the Issuer to the Issuing Agent pursuant to this Section shall survive the resignation or removal of the Issuing Agent and the satisfaction or termination of this Agreement.

SECTION 20. Amendments.

(a) This Agreement may be amended by any written instrument signed by the parties, so long as such amendment does not adversely affect the rights of the Registered Holders of Notes, as certified in writing by the Issuer to the Issuing Agent.

(b) The Issuer and the Issuing Agent agree to cooperate to adopt amendments or supplements to this Agreement from time to time to modify the restrictions and procedures for resales and other transfers of the Notes to reflect any change in applicable law or regulation (or the interpretation thereof) or in practices relating to the resale or transfer of restricted securities generally.

SECTION 21. Removal of Restrictions. Upon the consent of the Issuer and subject to the Issuer's right to require an opinion of counsel to the effect that the restrictions are no longer required under the Securities Act and in form acceptable to the Issuer, a Registered Holder may surrender its Note to the Issuing Agent who, upon written instructions of the Issuer, shall issue in exchange for that Note one or more unlegended Notes of any authorized denomination, of a like aggregate principal amount bearing a number not contemporaneously outstanding and containing identical terms and provisions. The Issuing Agent shall not deliver unlegended Notes without the written instructions of the Issuer.

SECTION 22. Issuer Information. The Issuer shall provide to any holder of a beneficial interest in any Note or any prospective purchaser of a Note or a beneficial interest therein, upon the request of such holder or prospective purchaser, the information regarding the Issuer required to be prepared by the Issuer pursuant to Rule 144A.

SECTION 23. Notices.

(a) All communications by or on behalf of the Issuer relating to the issuance, transfer, exchange or payment of the Notes or interest thereon shall be in writing and directed to the Issuing Agent at its address set forth in subsection (b)(ii) of this Section 23, and the Issuer will send all Notes to be completed, authenticated and delivered by the Issuing Agent to such address (or such other address as the Issuing Agent shall specify in writing to the Issuer).

(b) Notices and other communications hereunder shall (except to the extent otherwise expressly provided) be in writing, shall be deemed effective when received and shall be addressed as follows, or to such other addresses as the parties hereto shall specify from time to time:

(i) if to the Issuer:

Enogex LLC
515 Central Park Drive, Suite 110
Oklahoma City, Oklahoma 73105
Attention: Chief Financial Officer
Telephone: (405) 525-7788
Facsimile: (405) 525-5258

With a copy to:

Jones Day
77 West Wacker Drive
Chicago, Illinois 60601
Attention: Robert J. Joseph, Esq.
Telephone: (312) 782-3939
Facsimile: (312) 782-8585

(ii) if to the Issuing Agent:

UMB Bank, N.A.
1010 Grand Boulevard, 4th Floor
Kansas City, Missouri 64106
Attention: Corporate Trust Department
Telephone: (816) 860-3020
Telefax: (816) 860-3029

SECTION 24. Resignation or Removal of Issuing Agent. The Issuing Agent may at any time resign as such agent by giving written notice to the Issuer of such intention on its part, specifying the date on which its desired resignation shall become effective; *provided*, *however*, that such date shall be not less than thirty days after the giving of such notice by the Issuing Agent to the Issuer. The Issuing Agent may be removed at any time by the filing with it of an instrument in writing signed by a duly authorized officer of the Issuer and specifying such removal and the date upon which it is intended to become effective, which date shall not be less than 30 days from the date that notice is received. Such resignation or removal shall take effect on the date of the appointment by the Issuer of a successor Issuing Agent and the acceptance of such appointment by such successor Issuing Agent. In the event of resignation by the Issuing Agent or removal by the Issuer, if a successor agent has not been appointed by the date as of which the resignation or removal of the Issuing Agent is to be effective, as set forth in the resignation notice of the Issuing Agent referred to above, the Issuing Agent may, at the expense of the Issuer, petition any court of competent jurisdiction for appointment of a successor Issuing Agent.

SECTION 25. Cancellation of Unissued Notes. Upon the written request of the Issuer, the Issuing Agent shall cancel and return to the Issuer all unissued Notes in its possession at the time of such request; *provided*, *however*, that the Issuing Agent shall not be required to destroy cancelled Notes.

SECTION 26. Benefit of Agreement. This Agreement is solely for the benefit of the parties hereto, their successors and assigns and the Registered Holders of Notes and no other person shall acquire or have any right under or by virtue of this Agreement.

SECTION 27. Notes Held by the Issuing Agent. The Issuing Agent, in its individual or other capacity, may become the owner or pledgee of the Notes with the same rights it would have if it were not acting as issuing and paying agent hereunder.

SECTION 28. Governing Law. This Agreement is to be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the State of New York, without regard to principles of conflicts of laws.

SECTION 29. Counterparts. This Agreement may be executed by the parties hereto in any number of counterparts, and by each of the parties hereto in separate counterparts, each such counterpart, when so executed and delivered, shall be deemed to be an original, but all such counterparts shall together constitute but one and the same instrument.

[Signature page follows]

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed on their behalf by their officers thereunto duly authorized, all as of the day and year first above written.

ENOGEX LLC

By:	/s/ Sean Trauschke
Name:	Sean Trauschke
Title:	Vice President and Chief Financial Officer

UMB BANK, N.A.

By:	/s/ Anthony P. Hawkins
Name:	Anthony P. Hawkins
Title:	Vice President

[Signature Page to Issuing and Paying Agency Agreement]

EXHIBIT A—FORM OF 6.25% SENIOR NOTE DUE 2020

[FACE OF NOTE]

THIS SECURITY HAS NOT BEEN REGISTERED UNDER THE SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT"), OR THE SECURITIES LAWS OF ANY STATE OR OTHER JURISDICTION. NEITHER THIS SECURITY NOR ANY INTEREST OR PARTICIPATION HEREIN MAY BE REOFFERED, SOLD, ASSIGNED, TRANSFERRED, PLEDGED, ENCUMBERED OR OTHERWISE DISPOSED OF IN THE ABSENCE OF SUCH REGISTRATION OR UNLESS SUCH TRANSACTION IS EXEMPT FROM, OR NOT SUBJECT TO, SUCH REGISTRATION.

THE HOLDER OF THIS SECURITY, BY ITS ACCEPTANCE HEREOF OF A BENEFICIAL INTEREST HEREIN:

(1) REPRESENTS THAT (A) IT IS A "QUALIFIED INSTITUTIONAL BUYER" (AS DEFINED IN RULE 144A UNDER THE SECURITIES ACT) OR (B) IT IS ACQUIRING THIS NOTE IN AN OFFSHORE TRANSACTION IN COMPLIANCE WITH REGULATION S UNDER THE SECURITIES ACT; AND

(2) AGREES ON ITS OWN BEHALF AND ON BEHALF OF ANY INVESTOR ACCOUNT FOR WHICH IT HAS PURCHASED SECURITIES, TO OFFER, SELL OR OTHERWISE TRANSFER SUCH SECURITY, PRIOR TO THE DATE (THE "RESALE RESTRICTION TERMINATION DATE") THAT IS [IN THE CASE OF RULE 144A NOTES: ONE YEAR] [IN THE CASE OF REGULATION S NOTES: 40 DAYS] AFTER THE LATER OF THE ORIGINAL ISSUE DATE HEREOF AND THE LAST DATE ON WHICH THE ISSUER OR ANY AFFILIATE OF THE ISSUER WAS THE OWNER OF THIS SECURITY (OR ANY PREDECESSOR OF SUCH SECURITY), ONLY (A) TO THE ISSUER, (B) FOR SO LONG AS THE SECURITIES ARE ELIGIBLE FOR RESALE PURSUANT TO RULE 144A UNDER THE SECURITIES ACT, TO A PERSON IT REASONABLY BELIEVES IS A "QUALIFIED INSTITUTIONAL BUYER" AS DEFINED IN RULE 144A UNDER THE SECURITIES ACT THAT PURCHASES FOR ITS OWN ACCOUNT OR FOR THE ACCOUNT OF A QUALIFIED INSTITUTIONAL BUYER TO WHOM NOTICE IS GIVEN THAT THE TRANSFER IS BEING MADE IN RELIANCE ON RULE 144A, (C) PURSUANT TO OFFERS AND SALES THAT OCCUR OUTSIDE THE UNITED STATES WITHIN THE MEANING OF REGULATION S UNDER THE SECURITIES ACT, (D) PURSUANT TO A REGISTRATION STATEMENT THAT HAS BEEN DECLARED EFFECTIVE UNDER THE SECURITIES ACT OR (E) PURSUANT TO ANOTHER AVAILABLE EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE SECURITIES ACT, INCLUDING THE EXEMPTION PROVIDED BY RULE 144 UNDER THE SECURITIES ACT, IF AVAILABLE, IN EACH CASE, IN ACCORDANCE WITH THE APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES OR ANY OTHER APPLICABLE JURISDICTION AND SUBJECT TO THE ISSUER'S AND THE ISSUING AND PAYING AGENT'S RIGHT PRIOR TO ANY SUCH OFFER, SALE OR TRANSFER PURSUANT TO CLAUSES (B), (C) OR (E) TO REQUIRE THE DELIVERY OF AN OPINION OF COUNSEL, CERTIFICATION AND/OR OTHER INFORMATION SATISFACTORY TO EACH OF THEM; AND

(3) AGREES THAT IT WILL DELIVER TO EACH PERSON TO WHOM THIS NOTE OR AN INTEREST HEREIN IS TRANSFERRED A NOTICE SUBSTANTIALLY TO THE EFFECT OF THIS LEGEND.

[IN THE CASE OF REGULATION S NOTES: BY ITS ACQUISITION HEREOF, THE HOLDER HEREOF REPRESENTS THAT IT IS NOT A U.S. PERSON NOR IS IT PURCHASING FOR THE ACCOUNT OF A U.S. PERSON AND IS ACQUIRING THIS SECURITY IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH REGULATION S UNDER THE SECURITIES ACT.]

BY ACCEPTING A BENEFICIAL INTEREST IN THIS NOTE, EACH HOLDER HEREOF AND EACH SUBSEQUENT TRANSFEREE IS DEEMED TO REPRESENT AND WARRANT THAT (1)(A) IT IS NOT

(I) AN EMPLOYEE BENEFIT PLAN SUBJECT TO PART 4 OF SUBTITLE B OF TITLE I OF THE EMPLOYEE RETIREMENT INCOME SECURITY ACT OF 1974, AS AMENDED ("ERISA"), (II) A PLAN TO WHICH SECTION 4975 OF THE INTERNAL REVENUE CODE OF 1986, AS AMENDED (THE "CODE") APPLIES, (III) AN ENTITY WHOSE UNDERLYING ASSETS INCLUDE ASSETS OF A PLAN DESCRIBED IN (A) OR (B) BY REASON OF THE PLAN'S INVESTMENT IN THE ENTITY (EACH OF (I), (II) AND (III), A "BENEFIT PLAN INVESTOR"), (IV) A GOVERNMENTAL PLAN AS DEFINED IN SECTION 3(32) OF ERISA ("GOVERNMENTAL PLAN"), (V) A CHURCH PLAN AS DEFINED IN SECTION 3(33) OF ERISA THAT HAS NOT MADE AN ELECTION UNDER SECTION 410(d) OF THE CODE ("CHURCH PLAN") OR (VI) A NON-U.S. PLAN, (B) IT IS A BENEFIT PLAN INVESTOR AND ITS PURCHASE AND HOLDING OF THE NOTE WILL NOT RESULT IN A NON-EXEMPT PROHIBITED TRANSACTION UNDER SECTION 406 OR 407 OF ERISA OR SECTION 4975 OF THE CODE, OR (C)(I) IT IS A GOVERNMENTAL PLAN, A CHURCH PLAN OR A NON-U.S. PLAN AND (II) ITS PURCHASE AND HOLDING OF THE NOTE IS NOT SUBJECT TO (a) ERISA, (b) SECTION 4975 OF THE CODE OR (c) ANY OTHER FEDERAL, STATE, LOCAL OR NON-U.S. LAW THAT PROHIBITS, OR IMPOSES AN EXCISE OR PENALTY TAX ON, THE PURCHASE OR HOLDING OF THE NOTE; AND (2) EACH HOLDER AND SUBSEQUENT TRANSFEREE WILL PROMPTLY NOTIFY THE ISSUER AND THE ISSUING AND PAYING AGENT IF, AT ANY TIME, IT IS NO LONGER ABLE TO MAKE THE REPRESENTATIONS CONTAINED IN CLAUSE (1) ABOVE.

UNLESS THIS NOTE IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY (THE "DEPOSITARY") (55 WATER STREET, NEW YORK, NEW YORK) TO THE ISSUER HEREOF OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE OR PAYMENT, AND ANY NOTE ISSUED IS REGISTERED IN THE NAME OF CEDE & CO. OR SUCH OTHER NAME AS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITARY AND ANY PAYMENT IS MADE TO CEDE & CO., ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL SINCE THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN.

UNLESS AND UNTIL IT IS EXCHANGED IN WHOLE OR IN PART FOR NOTES IN CERTIFICATED FORM, THIS NOTE MAY NOT BE TRANSFERRED EXCEPT AS A WHOLE BY THE DEPOSITARY TO A NOMINEE OF THE DEPOSITARY OR BY A NOMINEE OF THE DEPOSITARY TO THE DEPOSITARY OR ANOTHER NOMINEE OF THE DEPOSITARY OR BY THE DEPOSITARY OR ANY SUCH NOMINEE TO A SUCCESSOR OF THE DEPOSITARY OR A NOMINEE OF SUCH SUCCESSOR.

6.25% SENIOR NOTE DUE 2020

CUSIP/ISIN: [29348QAB8/US29348QAB86] [U29293AB0/USU29293AB05]	NUMBER: [ ]
ORIGINAL ISSUE DATE(S): November 16, 2009	PRINCIPAL AMOUNT(S): $[ ]
INTEREST RATE: 6.25%	STATED MATURITY DATE: March 15, 2020
INTEREST PAYMENT DATE(S): March 15 and September 15, commencing March 15, 2010	RECORD DATE: Fifteenth day preceding the applicable Interest Payment Date
DEFAULT RATE: 8.25%	

Enogex LLC (the "Company", which term includes any successor entity), for value received, hereby promises to pay to Cede & Co., or registered assigns, the principal sum of $[ ] on the Stated Maturity Date specified above (or any prior date, including a Redemption Date (as defined on the reverse hereof), on which the principal, or an installment of principal, of this Note becomes due and payable, whether by the declaration of acceleration, call for redemption at the option of the Company or otherwise (the Stated Maturity Date or such prior date, as the case may be, is referred to herein as the "Maturity Date" with respect to the principal repayable on such date)) and to pay interest thereon, at the Interest Rate per annum specified above, until the principal hereof is paid or duly made available for payment, and (to the extent that the payment of such interest shall be legally enforceable) at the Default Rate per annum specified above on any overdue principal, premium and/or interest. The Company will pay interest in arrears on each Interest Payment Date specified above (each, an "Interest Payment Date"), commencing March 15, 2010, and on the Maturity Date. Interest on this Note will be computed on the basis of a 360-day year of twelve 30-day months.

Interest on this Note will accrue from, and including, the immediately preceding Interest Payment Date to which interest has been paid or duly provided for (or from, and including, the Original Issue Date if no interest has been paid or duly provided for with respect to this Note) to, but excluding, the applicable Interest Payment Date or the Maturity Date, as the case may be (each, an "Interest Period"). The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, subject to certain exceptions described herein, be paid to the person in whose name this Note (or one or more predecessor Senior Notes as defined on the reverse hereof) is registered at the close of business on the fifteenth calendar day (whether or not a Business Day, as defined below) immediately preceding such Interest Payment Date (the "Record Date"); *provided*, *however*, that interest payable on the Maturity Date will be payable to the person to whom the principal hereof and premium, if any, hereon shall be payable. Any such interest not so punctually paid or duly provided for ("Defaulted Interest") will forthwith cease to be payable to the holder on any Record Date, and shall be paid to the person in whose name this Note is registered at the close of business on a special record date (the "Special Record Date") for the payment of such Defaulted Interest to be fixed by the Issuing and Paying Agent hereinafter referred to, notice whereof shall be given to the holder of this Note by the Issuing and Paying Agent not less than 10 calendar days prior to such Special Record Date.

Payment of principal of, and premium, if any, and interest on this Note if in the form of one or more Global Notes (as defined on the reverse hereof) will be made by the Company through the Issuing and Paying Agent (as defined on the reverse hereof) to the Depository. Interest on this Note if in the form of a certificated security will be paid by check mailed to the holder at that holder's address as it appears in the register for the Senior Notes (as defined on the reverse hereof) maintained by the Issuing and Paying Agent; however, a holder of $10,000,000 or more of Senior Notes will be entitled to receive payments of interest by wire transfer to a bank within the continental United States, if appropriate wire transfer instructions have been received by the Issuing and Paying Agent on or prior to the applicable Record Date. Such wire instructions, upon receipt by the Issuing and Paying Agent, shall remain in effect until revoked by such holder. The principal, interest at maturity and premium, if any, on this Note if in the form of a certificated security will be payable in immediately available funds at the office of the Issuing and Paying Agent upon presentation of this Note. If required by law, the Issuing and Paying Agent will withhold any taxes or other governmental charges on any payment made in connection with this Note.

If any Interest Payment Date or the Maturity Date falls on a day that is not a Business Day, the required payment of principal, premium, if any, and/or interest will be made on the next succeeding Business Day with the same force and effect as if made on the date such payment was due, and no interest will accrue on such payment for the period from and after such Interest Payment Date or the Maturity Date, as the case may be, to the date of such payment on the next succeeding Business Day.

As used herein, "Business Day" means any day, other than a Saturday or Sunday, that is neither a legal holiday nor a day on which banking institutions are authorized or required by law or executive order to close in New York, New York.

The Company is obligated to make payment of principal, premium, if any, and interest in respect of this Note in U.S. dollars.

Reference is hereby made to the further provisions of this Note set forth on the reverse hereof, which further provisions shall have the same force and effect as if set forth on the face hereof.

IN WITNESS WHEREOF, Enogex LLC has caused this Note to be executed.

ENOGEX LLC

By: ______________________________
Name: ______________________________
Title: ______________________________

Countersigned for Authentication only
on ________________________.

UMB Bank, N.A.,
as Issuing and Paying Agent

By: ______________________________
Name: ______________________________
Title: Authorized Signatory

This Note is not valid for any purpose unless countersigned by UMB Bank, N.A., as Issuing and Paying Agent.

[REVERSE OF NOTE]

ENOGEX LLC

6.25% SENIOR NOTE DUE 2020

This Note is one of a duly authorized series of Senior Notes of the Company, designated as 6.25% Senior Notes due 2020 (the "Senior Notes") issued and to be issued under an Issuing and Paying Agency Agreement, dated as of November 15, 2009 (as amended, modified or supplemented from time to time, the "Issuing and Paying Agency Agreement"), between the Company and UMB Bank, N.A., as Issuing and Paying Agent (the "Issuing and Paying Agent", which term includes any successor issuing and paying agent under the Issuing and Paying Agency Agreement), to which the Issuing and Paying Agency Agreement and all agreements supplemental thereto reference is hereby made for a statement of the respective rights, duties and obligations thereunder of the Company, the Issuing and Paying Agent and the holders of the Senior Notes, and of the terms upon which the Senior Notes are, and are to be, authenticated and delivered. All terms used but not otherwise defined in this Note shall have the meanings assigned to such terms in the Issuing and Paying Agency Agreement.

This Note, and any Senior Note or Notes issued upon transfer hereof, is issuable only in fully registered form (a "Global Note"), without coupons, in denominations of $2,000 and integral multiples of $1,000 in excess thereof (an "Authorized Denomination"). The Issuing and Paying Agent has been appointed registrar for the Senior Notes, and the Company will cause the Issuing and Paying Agent to maintain at its office (or drop agent) in The City of New York a register for the registration and transfer of Senior Notes. This Note may be transferred at the aforesaid office of the Issuing and Paying Agent by surrendering this Note for cancellation, duly endorsed or accompanied by a written instrument of transfer in form approved by the Issuing and Paying Agent and duly executed by the registered holder hereof in person or by the holder's attorney duly authorized in writing, and thereupon the Issuing and Paying Agent will issue in the name of the transferee or transferees, in exchange herefor, a new Senior Note or Notes having identical terms and provisions and having a like aggregate principal amount in Authorized Denominations, subject to the terms and conditions set forth herein and in the Issuing and Paying Agency Agreement, without charge except for any tax or other governmental charge imposed in relation thereto. The Issuing and Paying Agent is not required to exchange or register the transfer of any Senior Note during the period of 15 days immediately preceding the date of first giving any notice of redemption or after such Note has been selected for redemption.

This Note is not subject to any sinking fund.

This Note will be subject to redemption at the option of the Company at any time or in part from time to time, at the Company's option, at a redemption price (the "Redemption Price") equal to the greater of:

- 100% of the principal amount of the Note to be redeemed; or
- the sum of the present values of the remaining scheduled payments of principal and interest on the Note to be redeemed (not including any portion of such payments of interest accrued to the date of redemption (the "Redemption Date")) discounted to the Redemption Date on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate plus 45 basis points;

plus, in each case, accrued and unpaid interest on the principal amount being redeemed to the Redemption Date.

"Treasury Rate" means, with respect to any Redemption Date:

- the yield, under the heading which represents the average for the immediately preceding week, appearing in the most recently published statistical release designated "H.15(519)" or any successor publication which is published weekly by the Board of Governors of the Federal Reserve System and which establishes yields on actively traded U.S. Treasury securities adjusted to constant maturity under the caption "Treasury Constant Maturities," for the maturity corresponding to the Comparable Treasury Issue (if no maturity is within three months before or after the Remaining Life (as defined below), yields for the two published maturities most closely corresponding to the Comparable Treasury Issue will be determined and the Treasury Rate will be interpolated or extrapolated from such yields on a straight line basis, rounding to the nearest month); or

- if such release (or any successor release) is not published during the week preceding the calculation date or does not contain such yields, the rate per annum equal to the semiannual equivalent yield to maturity of the Comparable Treasury Issue, calculated using a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such Redemption Date.

The Treasury Rate will be calculated on the third business day preceding the Redemption Date.

"Comparable Treasury Issue" means the U.S. Treasury security selected by an Independent Investment Banker as having a maturity comparable to the remaining term ("Remaining Life") of the Senior Notes that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the Senior Notes.

"Comparable Treasury Price" means (1) the average of five Reference Treasury Dealer Quotations for such Redemption Date, after excluding the highest and lowest Reference Treasury Dealer Quotations, or (2) if the Independent Investment Banker obtains fewer than four such Reference Treasury Dealer Quotations, the average of all such quotations.

"Independent Investment Banker" means J.P. Morgan Securities Inc., Mitsubishi UFJ Securities (USA), Inc., Wells Fargo Securities, LLC, or another independent investment banking institution of national standing appointed by us.

"Reference Treasury Dealer" means (1) J.P. Morgan Securities Inc. or its successor and a primary U.S. government securities dealer in the United States (a "primary treasury dealer") selected by each of Mitsubishi UFJ Securities (USA), Inc. and Wells Fargo Securities, LLC, or their respective successors, *provided*, *however*, that if any of the foregoing ceases to be a primary treasury dealer, we will substitute therefor another primary treasury dealer and (2) any other primary treasury dealer selected by us after consultation with the Independent Investment Banker.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any Redemption Date, the average, as determined by the Independent Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Independent Investment Banker at 5:00 p.m., New York City time, on the third business day preceding such Redemption Date.

The Company will mail a notice of redemption to each holder of the Senior Notes by first-class mail at least 30 and not more than 60 days prior to the Redemption Date. Unless the Company defaults on the payment of the Redemption Price, interest will cease to accrue on the Senior Notes or portions thereof called for redemption. If fewer than all of the Senior Notes are to be redeemed, the Issuing and Paying Agent will select, not more than 60 days prior to the Redemption Date, the particular Senior Notes or portions thereof for redemption from the outstanding Senior Notes not previously called by such method as the Issuing and Paying Agent deems fair and appropriate.

If at the time of mailing the notice of redemption, the Company has not irrevocably directed the Issuing and Paying Agent to redeem the Senior Notes called for redemption, the notice may state that the redemption is subject to the receipt of the redemption moneys by the Issuing and Paying Agent on or prior to the Redemption Date and that the notice will be of no effect unless such moneys are received on or prior to such Redemption Date.

Liens. The Company will not, and will not permit any Subsidiary (as hereinafter defined) to, pledge or otherwise subject to any lien any of its property or assets (whether now or hereafter acquired and whether tangible or intangible) unless the Senior Notes are secured by such pledge or lien equally and ratably with all other obligations and indebtedness secured thereby so long as such other obligations and indebtedness shall be so secured.

The agreement of the Company contained in this paragraph does not apply to “Permitted Encumbrances.” Permitted Encumbrances means:

(1) any lien on any asset securing indebtedness, including a capital lease, incurred or assumed for the purpose of financing all or any part of the cost of acquiring, repairing, constructing or improving such asset; provided that such lien attaches to such asset concurrently with or within 12 months after the acquisition thereof or the completion of the repair, construction or improvement thereof (including, without limitation, liens in favor of the United States of America or any state thereof, or any department, agency or instrumentality or political subdivision of the United States of America or any state thereof, or for the benefit of holders of securities issued by any such entity to finance any of the foregoing).

(2) any lien on any asset of any person existing at the time such person is merged or consolidated with or into the Company or any of its Subsidiaries and not created in contemplation of such event.

(3) any lien existing on any asset prior to the acquisition thereof by the Company or any of its Subsidiaries and not created in contemplation of such acquisition.

(4) any lien arising out of the refinancing, extension, renewal or refunding of any debt secured by any lien permitted by any of the foregoing clauses or clauses (14), (15) or (19); provided that such debt is not increased and is not secured by any additional assets.

(5) liens for taxes, assessments or other governmental charges or levies not yet due or which are being contested in good faith by appropriate proceedings and with respect to which adequate reserves or other appropriate provisions are being maintained in accordance with generally accepted accounting principles (“GAAP”).

(6) statutory liens of landlords and liens of carriers, warehousemen, mechanics, materialmen, and interest owners of oil and gas production and other liens imposed by law, created in the ordinary course of business and for amounts not past due for more than 60 days or which are being contested in good faith by appropriate proceedings, properly instituted and diligently conducted and with respect to which adequate reserves or other appropriate provisions are being maintained in accordance with GAAP.

(7) liens incurred or deposits made in the ordinary course of business (including, without limitation, surety bonds and appeal bonds) in connection with pension or retirement plans, workers’ compensation, unemployment insurance and other types of social security benefits or to secure the performance of tenders, bids, leases, contracts (other than for the prepayment of debt), statutory obligations and other similar obligations or arising as a result of progress payments under government contracts.

(8) easements (including, without limitation, reciprocal easement agreements and utility agreements), rights of way, covenants, consents, reservations, encroachments, variations and other restrictions, charges or encumbrances (whether or not recorded) affecting the use of real property.

(9) attachment, judgment and other similar liens arising in connection with court proceedings, provided the execution or other enforcement of such liens is effectively stayed and the claims secured thereby are being contested in good faith in such a manner that the property subject to such liens is not subject to forfeiture.

(10) liens on deposits required by any person with whom the Company or any of its Subsidiaries enters into Swap Agreements or any credit support therefor, in each case, in the ordinary course of business for the purpose of directly mitigating risks associated with liabilities, commitments, investments, assets or property held or reasonably anticipated.

(11) liens, including liens imposed by environmental laws, arising in the ordinary course of its business that (i) do not secure indebtedness, (ii) do not secure obligations in an aggregate amount

exceeding $40,000,000 at any time, and (iii) do not in the aggregate materially detract from the value of its assets or materially impair the use thereof in the operation of its business.

(12) deposits securing liability to insurance carriers under insurance or self-insurance arrangements.

(13) liens securing indebtedness of a Subsidiary to the Company or another Subsidiary.

(14) liens created or assumed by a Subsidiary on any contract for the permitted sale of any product or service or any proceeds therefrom (including accounts and other receivables).

(15) liens created by a Subsidiary on advance payment obligations by such Subsidiary to secure indebtedness incurred to finance advances for oil, gas hydrocarbon and other mineral exploration and development.

(16) liens securing obligations, neither assumed by the Company or any Subsidiary nor on account of which the Company or any Subsidiary customarily pays interest, upon real estate or under which the Company or any Subsidiary has a right-of-way, easement, franchise or other servitude or of which the Company or any Subsidiary is the lessee of the whole thereof or any interest therein for the purpose of locating pipe lines, substations, measuring stations, tanks, pumping or delivery equipment or similar equipment.

(17) liens arising by virtue of any statutory or common law provision relating to banker's liens, rights of setoff or similar rights as to deposit accounts or other funds maintained with a depository institution and liens of a collecting bank arising in the ordinary course of business under Section 4-208 of the Uniform Commercial Code in effect in the relevant jurisdiction covering only the items being collected upon.

(18) liens granted to the administrative agent for the benefit of the lenders under the Company's revolving credit facility in respect of cash collateral for letters of credit issued under the facility.

(19) liens existing on the date of the Issuing and Paying Agency Agreement.

(20) liens arising in connection with a receivables securitization program securing indebtedness in an aggregate amount not to exceed at any one time outstanding 5% of Consolidated Tangible Net Assets.

(21) liens incurred in the ordinary course of business in connection with leases and subleases of real property owned or leased by the Company or any Subsidiary and not interfering with the ordinary conduct of the business of the Company and the Subsidiaries.

(22) other liens securing indebtedness in an aggregate amount not to exceed at any one time outstanding 15% of Consolidated Tangible Net Assets.

"Consolidated Tangible Net Assets" means, as of any date of determination, the total amount of consolidated assets of the Company and its Subsidiaries minus: (1) all current liabilities (excluding (a) any current liabilities that by their terms are extendable or renewable at the option of the obligor thereon to a time more than 12 months after the time as of which the amount thereof is being computed and (b) current maturities of long-term debt) and (2) the value (net of any applicable reserves and accumulated amortization) of all goodwill, trade names, trademarks, patents and other like intangible assets, all as set forth, or on a pro forma basis would be set forth, on the consolidated balance sheet of the Company and its Subsidiaries for the most recently completed fiscal quarter or year, as applicable, prepared in accordance with GAAP.

"Subsidiary" means any corporation or other entity of which the Company and/or any other Subsidiary (within the meaning of this definition) owns (whether directly or indirectly) securities or other ownership interests having ordinary voting power to elect a majority of the board of directors or other persons performing similar functions.

"Swap Agreement" means any agreement with respect to any swap, forward, future or other derivative transaction or option or similar agreement entered into by the Company or any Subsidiary in order to provide protection to the Company and/or a Subsidiary against fluctuations in future interest rates, currency exchange rates or commodity prices.

Sale and Leaseback. The Company will not, and will not permit any Subsidiary to, enter into any agreement providing for the leasing by the Company or such Subsidiary of all or substantially all of the property of the Company or such Subsidiary, which property has been or is to be sold or transferred by the Company or such Subsidiary to the lessor thereof, or which is substantially similar in purpose to property so sold.

Merger, Consolidation, Etc. The Company shall not consolidate with or merge into any other entity or convey or transfer all or substantially all of its properties and assets as an entirety to any person, unless:

(1) the entity formed by such consolidation or into which the Company is merged or the person which acquires by conveyance or transfer the properties and assets of the Company substantially as an entirety shall be an entity organized and existing under the laws of the United States of America, any State thereof or the District of Columbia (the "Successor Entity") and shall expressly assume, by amendment to the Issuing and Paying Agency Agreement signed by the Company and such Successor Entity and delivered to the Issuing and Paying Agent, the due and punctual payment of the principal of, premium, if any, and interest on all the Senior Notes and the performance or observance of every covenant hereof and of the Issuing and Paying Agency Agreement on the part of the Company to be performed or observed; and

(2) the Company shall have delivered to the Issuing and Paying Agent a certificate signed by an executive officer of the Company and a written opinion of counsel satisfactory to the Issuing and Paying Agent, each stating that such transaction and such amendment to the Issuing and Paying Agency Agreement comply with this paragraph and that all conditions precedent herein provided for relating to such transaction have been complied with.

Upon any such consolidation or merger, or any conveyance or transfer of all or substantially all of the properties and assets of the Company as an entirety in accordance with this paragraph, the Successor Entity shall succeed to, and be substituted for, and may exercise every right and power of, the Company under the Issuing and Paying Agency Agreement and the Senior Notes with the same effect as if the Successor Entity had been named as the Company therein and thereafter the Company shall be released from its liability as obligor on any of the Senior Notes and under the Issuing and Paying Agency Agreement.

For purposes of the foregoing, "all or substantially all of its properties and assets" shall mean 50% or more of the total assets of the Company as shown on the consolidated balance sheet of the Company as of the end of the calendar year immediately preceding the day of the year in which such determination is made. Further, nothing in the Issuing and Paying Agency Agreement prevents or hinders the Company from selling, transferring or otherwise disposing during any calendar year (in one transaction or a series of transactions) less than 50% of the amount of its total assets as shown on the consolidated balance sheet of the Company as of the end of the immediately preceding calendar year.

Events of Default. The registered holder of this Note may, by notice in writing to the Company, declare the principal of this Note to be, and the same shall thereupon become, forthwith due and payable, together with interest accrued thereon, upon the occurrence and continuation of one or more of the following events of default:

(1) default in the payment of any interest on this Note when due or in the payment of any interest on any other Senior Note when due, which default continues and remains unremedied for at least 30 calendar days;

(2) default in the payment of principal or redemption price, as the case may be, on this Note or on any other Senior Note when due on the Maturity Date;

(3) a judgment, decree or order by a court having jurisdiction shall have been entered adjudicating the Company or any Significant Subsidiary (which term for purposes of this Note shall mean any subsidiary of the Company that would, under the standards set forth in Rule 405 of Regulation C under the Securities Act be a "Significant Subsidiary" as defined therein) bankrupt or insolvent, or approving as properly filed a petition seeking reorganization of the Company or any Significant Subsidiary under the United States Bankruptcy Code or any other similar applicable Federal or state law, and such judgment, decree or order shall not have been vacated or set aside or stayed within 60 days of its entry; or a judgment, decree or order of a court having jurisdiction for the appointment of a receiver or liquidator or trustee or assignee in bankruptcy or insolvency of the Company or of any Significant Subsidiary or of the whole or any substantial part of the property of any thereof, or for the winding up or liquidation of the affairs of any thereof, shall have been entered, and such judgment, decree or order shall not have been vacated or set aside or stayed within 60 days of its entry;

(4) the Company or any Significant Subsidiary shall institute proceedings to be adjudicated a voluntary bankrupt, or shall consent to the filing of a bankruptcy proceeding against it, or shall file a petition or answer or consent seeking reorganization under the United States Bankruptcy Code or any other similar applicable Federal or state law, or shall consent to the filing of any such petition, or shall consent to the appointment of a receiver or liquidator or trustee or assignee in bankruptcy or insolvency of it or of the whole or any substantial part of U.S. property, or shall make an assignment for the benefit of creditors, or shall admit in writing its inability to pay its debts generally as they become due;

(5) the Company shall fail to perform or observe any other term, covenant or agreement contained in this Note to be performed or observed by it, and any such failure shall continue and remain unremedied for at least 30 calendar days after notice has been given in writing to the Company by the holder hereof, or

(6) the Company or any Subsidiary shall default in the payment when due (subject to any applicable grace period) whether at stated maturity or otherwise, of any principal of or interest on (howsoever designated) any indebtedness for borrowed money of, or guaranteed by, the Company or any Subsidiary (except any such indebtedness of any Subsidiary to the Company or to any other such Subsidiary), whether such indebtedness now exists or shall hereafter be created if the aggregate principal amount of all such indebtedness as to which such default has occurred equals or exceeds $40,000,000.

Defeasance. If, at or prior to the maturity of this Note, the Company shall deposit with the Issuing and Paying Agent, in trust for the benefit of the holder hereof, either:

(1) cash sufficient to pay the principal of and premium, if any, and interest on this Note as and when the same become due and payable, including upon redemption prior to maturity, or

(2) such amount of U.S. Government Securities (which term shall mean, for the purposes of this Note, direct obligations of the United States of America to pay principal which obligations are not callable at the issuer's option, or direct obligations of the United States of America to pay interest, in each case for the payment of which the full faith and credit of the United States of America is pledged) as will together with the income to accrue thereon without consideration of any reinvestment thereof be sufficient to pay the principal of and premium, if any, and interest on this Note as and when the same become due and payable, including upon redemption prior to maturity,

then in such case, the Company shall be deemed to have satisfied and discharged this Note, *provided* that if this Note is to be redeemed prior to maturity, this Note will not be deemed satisfied and discharged until such Note has been irrevocably called or designated for redemption on a date when this Note may be called for redemption and proper notice of redemption has been given as provided herein or the Company has given the Issuing and Paying Agent irrevocable instructions to give such notice of redemption.

No provision of this Note or of the Issuing and Paying Agency Agreement shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay principal, premium, if any, and interest in respect of this Note at the times, places and rate of formula, and In the coin or currency, herein prescribed.

Prior to due presentment of this Note for registration of transfer, the Company, the Issuing and Paying Agent and any agent of the Company or the Issuing and Paying Agent may treat the holder in whose name this Note is registered as the owner hereof for all purposes, whether or not this Note be overdue, and neither the Company, the Issuing and Paying Agent nor any such agent shall be affected by notice to the contrary.

Any action by the holder of this Note shall bind all future holders of this Note, and of any Note issued in substitution herefor or in place hereof, in respect of anything done or permitted by the Company or the Issuing and Paying Agent in pursuance of such action.

So long as this Note shall be outstanding, the Company will maintain an office or agency for the payment of the principal of, premium, if any, and interest on this Note as herein provided in the Borough of Manhattan, The City of New York, and an office or agency in said Borough of Manhattan for the registration and transfer as aforesaid of the Senior Notes. The Company may designate other agencies for the payment of said principal, premium, if any, and interest at such place or places (subject to applicable laws and regulations) as the Company may decide. So long as there shall be an Issuing and Paying Agent, the Company shall keep the Issuing and Paying Agent advised of the names and locations of such agencies, if any agency is so designated.

Any moneys deposited with the Issuing and Paying Agent for the payment of the principal of, premium, if any, or interest on any Senior Notes, and remaining unclaimed at the end of two years after the last of such principal or interest shall have become due and payable (whether at maturity or otherwise), shall then be repaid to the Company and upon such repayment all liability of the Issuing and Paying Agent with respect to such moneys shall thereupon cease, without, however, limiting in any way any obligation which the Company may have to pay the principal of, premium, if any, or interest on this Note as the same shall become due.

The Issuing and Paying Agency Agreement and this Note shall be governed by and construed in accordance with the laws of the State of New York applicable to agreements made and to be performed entirely in such State, without regard to principles of conflicts of laws.

ABBREVIATIONS

The following abbreviations, when used in the inscription on the face of this Note, shall be construed as though they were written out in full according to applicable laws or regulations:

TEN COM-	as tenants in common	UNIF GIFT MIN ACT- ______ Custodian ______ (Cust) (Minor)
TEN ENT-	as tenants by the entireties	Under Uniform Gifts to Minors Act
JT ENT-	as joint tenants with right of survivorship and not as tenants in common	______ State

Additional abbreviations may also be used though not in the above list.

FOR VALUE RECEIVED, the undersigned hereby sell (s),
Assign (s) and transfer (s) unto

PLEASE INSERT SOCIAL SECURITY OR OTHER
IDENTIFYING NUMBER OF ASSIGNEE

______

______

______

Please print or typewrite name and address
including postal zip code of assignee

______

the within Note and all rights thereunder hereby irrevocably constituting and appointing attorney to transfer said Note on the books of the Issuing and Paying Agent, with full power of substitution in the premises.

Dated ______

______

NOTICE: The signature to this assignment must correspond with the name as written upon the face of the within instrument in every particular, without alteration or enlargement or any change whatever.

Signature Guaranteed By:

(Name of Eligible Guarantor Institution as defined by SEC Rule 17 Ad-15 (17 CFR 240.17 Ad-15))

By:

Name

Title:

EXHIBIT B—FORM OF BOND POWER

[Form of Bond Power]

FOR VALUE RECEIVED the undersigned Registered Holder(s) hereby sell(s), assign(s) and transfer(s) unto

____

____

____

(please print or typewrite name, address, including postal zip code, and Taxpayer identification number of assignee) the attached Note and all rights thereunder, hereby irrevocably constituting and appointing ______________________________ attorney to transfer said Note on the books of the issuer with full power of substitution in the premises.

In connection with any transfer of the attached Note of Enogex LLC (the "Company"), the undersigned confirms that without utilizing any general solicitation or general advertising:

[Check One]

o (a) The Note is being transferred by the undersigned to a "qualified institutional buyer" (as defined in Rule 144A under the Securities Act of 1933, as amended (the "Securities Act")) acting for its own account or for the account of another "qualified institutional buyer" in reliance upon the exemption from the registration provisions of Section 5 of the Securities Act provided by Rule 144A thereunder.

or

o (b) The Note is being transferred by the undersigned to a person who is not a "U.S. person" (as defined in Rule 902 of Regulation S under the Securities Act ("Regulation S")) in a transaction or transactions taking place outside the United States in accordance with Regulation S.

or

o (c) The Note is being transferred pursuant by the undersigned in reliance upon the exemption from the registration provisions of Section 5 of the. Securities Act provided by ____.

The undersigned also confirms that it did not purchase the Note as part of the initial distribution thereof and that the transfer is being effected pursuant to and in accordance with an exemption from registration under the Securities Act.

The Issuing and Paying Agent will not register the Note in the name of any person other than the Registered Holder(s) thereof unless (1) one of the foregoing boxes is checked and (2) the other conditions to any such transfer of registration set forth on the face of the Note and in Section 12 of the Issuing and Paying Agency Agreement shall have been satisfied.

Dated: ____________________________________ By: ____

NOTICE: The signature of the Registered Holder(s) to this assignment must correspond with the name as written upon the face of the attached Note.

TO BE COMPLETED BY PURCHASER IF (a) ABOVE IS CHECKED:

The undersigned represents and warrants that it is a “qualified institutional buyer” (as defined in Rule 144A under the Securities Act) and that it is acquiring the Note for its own account or for accounts for which it exercised sole investment discretion and that, if applicable, each account is a “qualified institutional buyer.” The undersigned acknowledges that it has received such information regarding the Company as the undersigned has requested pursuant to Rule 144A or has determined not to request such information and that it is aware that the Registered Holder(s) is relying upon the foregoing representations in order to claim the exemption from the registration provisions of Section 5 of the Securities Act provided by Rule 144A. The undersigned acknowledges that the Note cannot be resold unless registered under the Securities Act or pursuant to an exemption from registration under the Securities Act.

(Name of Transferee)

Dated: ____________________ By: ____________________

NOTICE: To be executed by an executive officer.

TO BE COMPLETED BY PURCHASER IF (b) ABOVE IS CHECKED:

The undersigned represents and warrants that it is not a "U.S. person" (as defined in Rule 902 of Regulation S under the Securities Act) and that it is acquiring the Note in a transaction or transactions taking place outside the United States in accordance with Regulation S. The undersigned acknowledges that the Note cannot be resold unless registered under the Securities Act or pursuant to an exemption from registration under the Securities Act.

(Name of Transferee)

Dated: ______________________ By: ______________________

NOTICE: To be executed by an executive officer.

OGE ENERGY CORP.
DIRECTORS' COMPENSATION

Compensation of non-officer directors of the Company during 2009 included an annual retainer fee of $100,000, of which $35,000 was payable in cash in monthly installments and $65,000 was deposited in the director's account under the Company's Deferred Compensation Plan in December 2009 and converted to 1,817.6734 common stock units based on the closing price of the Company's Common Stock on December 4, 2009. All non-officer directors received $1,200 for each Board meeting and $1,200 for each committee meeting attended. The lead director and the chairman of the audit committee received an additional $10,000 cash retainer. The chairmen of the compensation and nominating and corporate governance committees received an additional $5,000 annual cash retainer in 2009. Each chairman of a board committee also received a meeting fee of $1,200 for each meeting (either in person or by phone) with management to address committee matters. Each member of the audit committee also received an additional annual retainer of $5,000. These amounts represent the total fees paid to directors in their capacities as directors of the Company and OG&E during 2009.

Under the Company's Deferred Compensation Plan, non-officer directors may defer payment of all or part of their attendance fees and the cash portion of their annual retainer fee, which deferred amounts are credited to their account as of the first of the month in which the deferred amounts otherwise would have been paid. Amounts credited to the accounts are assumed to be invested in one or more of the investment options permitted under the Deferred Compensation Plan. During 2009, those investment options included an OGE Energy common stock fund, whose value was determined based on the stock price of the Company's Common Stock, and various money market, bond and equity funds. When an individual ceases to be a director of the Company, all amounts credited under the Deferred Compensation Plan are paid in cash in a lump sum or installments.

In December 2009, the compensation committee met to consider director compensation. At that meeting, the compensation committee increased the cash portion of the annual retainer to $37,500 from $35,000 and increased the meeting fee from $1,200 to $1,500.

Historically, for those directors who retired from the Board of Directors after 10 years or more of service, the Company and OG&E continued to pay their annual cash retainer until their death. In November 1997, the Board eliminated this retirement policy for directors. Directors who retired prior to November 1997, however, will continue to receive benefits under the former policy.

OGE ENERGY CORP.
EXECUTIVE OFFICER COMPENSATION

Executive Compensation

In December 2009, the Compensation Committee (the "Committee") of the OGE Energy Corp. board of directors took actions setting executives' salaries, target amount of annual bonus awards and target amounts of long-term compensation awards for 2010. Executive compensation was set by the Committee after consideration of, among other things, individual performance and market-based data on compensation for executives with similar duties. Payouts of 2010 annual bonus targets and long-term awards are dependent on achievement of specified corporate goals that will be established by the Committee at a subsequent meeting, and no officer is assured of any payout.

Salary

The Committee established the base salaries for its senior executive group. The salaries for 2010 for the current OGE Energy officers who are expected to be named in the Summary Compensation Table in OGE Energy's 2010 Proxy Statement (the "Named Executive Officers") are as follows:

Named Executive Officer	2010 Base Salary
Peter B. Delaney, Chairman and Chief Executive Officer	$840,000
Danny P. Harris, Senior Vice President and Chief Operating Officer	$562,300
Sean Trauschke, Vice President and Chief Financial Officer	$412,000
E. Keith Mitchell, Senior Vice President and Chief Operating Officer of Enogex LLC	$331,300
Stephen E. Merrill, Vice President of Human Resources	$254,800
Scott Forbes, Controller and Chief Accounting Officer	$245,100

Establishment of 2010 Annual Incentive Awards

As stated above, at its December 2009 meeting, the Committee approved the target amount of annual incentive awards, expressed as a percentage of salary, with the officer having the ability, depending upon achievement of the 2010 corporate goals to be set by the Committee at a subsequent meeting, to receive from 0 percent to 150 percent of such targeted amount. For 2010, the targeted amount ranged from 40 percent to 90 percent of the approved 2010 base salary for the Named Executive Officers.

Establishment of Long-Term Awards

At its December 2009 meeting, the Committee also approved the level of target long-term incentive awards, expressed as a percentage of salary, with the officer having the ability to receive from 0 percent to 200 percent of such targeted amount at the end of a three-year performance period depending upon achievement of the corporate goals to be set by the Committee at a subsequent meeting. For 2010, the targeted amount ranged from 70 percent to 225 percent of the approved 2010 base salary for the Named Executive Officers.

Other Benefits

Retirement Benefits. Virtually all of our employees hired before December 1, 2009, including executive officers, are eligible to participate in our Pension Plan and certain employees are eligible to participate in our supplemental restoration plan that enables participants, including executive officers, to receive the same benefits that they would have received under our Pension Plan in the absence of limitations imposed by the Federal tax laws. In addition, a Supplemental Executive Retirement Plan (the "SERP"), which was adopted in 1993, offers supplemental pension benefits to specified lateral hires. Mr. Delaney is the only employee, including executive officers, who participates in the SERP. Mr. Delaney's participation in the SERP was the result of arms-length bargaining between Mr. Delaney and the Company at the time of his hire in April 2002 as Executive Vice President of the Company.

Almost all employees of the Company, including executive officers, also are eligible to participate in our qualified defined contribution retirement plan (the "401(k) Plan"). Under the 401(k) Plan, participants may contribute between two percent and 19 percent of their compensation. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Internal Revenue Code subject to the limitations thereof; or (ii) a contribution made on an after-tax basis. In addition, participants age 50 or older may make as a before-tax contribution certain "catch-up" contributions as permitted under the Internal Revenue Code. The 401(k) Plan was amended in October 2009 whereby eligible employees were offered a one-time irrevocable election (the "Choice Program"), depending on their hire date, to select a future retirement benefit combination from the Company's Pension Plan and the Company's 401(k) Plan. If employees elected under the Choice Program to stay in the current Pension Plan and 401(k) Plan, the Company matches (other than the "catch-up contributions"), each pay period under the 401(k) Plan, on behalf of each participant, an amount equal to 50 percent up to six percent of compensation for participants whose employment or re-employment date occurred before February 1, 2000 and who have less than 20 years of service, as defined in the 401(k) Plan, and an amount equal to 75 percent up to six percent of compensation for participants whose employment or re-employment date occurred before February 1, 2000 and who have 20 or more years of service, as defined in the 401(k) Plan. For participants whose employment or re-employment date occurred on or after February 1, 2000 and before December 1, 2009 under the current 401(k) Plan, the Company contributes 100 percent up to six percent of compensation. For participants hired on or after December 1, 2009, the Company contributes, effective January 1, 2010, 200 percent up to five percent of compensation. If employees elected under the Choice Program not to stay in the current Pension Plan and 401(k) Plan, effective January 1, 2010, the Company will contribute on behalf of each participant, depending on the option elected under the Choice Program, 200 percent up to five percent of compensation or 100 percent up to six percent of compensation. Participants' contributions are fully vested and non-forfeitable. The Company match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their Company contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Company's Pension Plan, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by the Company or its affiliates.

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The deferred compensation plan allows key employees, including all executive officers, to defer compensation above government limitations on 401(k) contributions that apply to the Company's 401(k) Plan and to defer taxation on all earnings on compensation deferred into the plan. Under the terms of the deferred compensation plan, participants have the opportunity to elect to defer each year up to 70 percent of their base salary and up to 100 percent of their annual bonus awards.

The Company matches deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on the option the participant elected under the Choice Program discussed above, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after six years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan.

Deferrals, plus any Company match, are credited to a special recordkeeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. During 2009, those investment fund options included an OGE Energy Common Stock fund and various money market, bond and equity funds.

Normally, payments under the deferred compensation plan begin within one year after retirement. For these purposes, normal retirement age is 65 and the minimum age to qualify for early retirement is age 55 with at least five years of service. Benefits will be paid, at the election of the participant, either in a lump sum or a stream of annual payments for up to 15 years, or a combination thereof. Participants whose employment terminates before they qualify for retirement will receive their vested account balance in one lump sum following termination as provided in the plan. Participants also will be entitled to pre- and post-retirement survivor benefits. If the participant dies while in employment before retirement, his or her beneficiary will receive a payment of the account balance plus a supplemental survivor benefit equal to two times the total amount of base salary and bonuses deferred under the plan. If the participant dies following retirement, his or her beneficiary will continue to receive the remaining vested account balance. Additionally, eligible surviving spouses will be entitled to a lifetime survivor annuity payable annually. The amount of the annuity is based on 50 percent of the participant's account balance at retirement, the spouse's age and actuarial assumptions established by the Company's Benefits Committee.

At any time prior to retirement, a participant may withdraw all or part of amounts attributable to his or her vested account balance at December 31, 2004, subject to a penalty of 10 percent of the amount withdrawn. In addition, at the time of the initial deferral election, a participant may elect to receive one or more in-service distributions on specified dates without penalty. Hardship withdrawals, without penalty, of amounts attributable to a participant's vested account balance as of December 31, 2004 may also be permitted at the discretion of the Company's Benefits Committee.

Perquisites. The Company also offers executive officers a limited amount of perquisites. These include dining and country club memberships for certain executive officers, an annual physical exam for all executive officers and, in the case of

Mr. Delaney, use of a Company car. A prior perquisite for tax and financial planning services was discontinued by the Committee during 2007. In reviewing the perquisites and the benefits under the SERP, 401(k) Plan, deferred compensation plan, Pension Plan and related restoration plan, the Committee sought in 2009 to provide participants with benefits at least commensurate with those offered by other utilities of comparable size.

Change-of-Control Provisions and Employment Agreements. Each of the executive officers has an employment agreement that provides for specified benefits upon termination following a change of control. If an executive officer's employment is terminated by the Company "without cause" or by the executive for "good reason" (as defined) following a change of control, the executive officer is entitled to, among other things, a severance payment equal to 2.99 times the sum of such officer's (a) annual base salary and (b) highest recent annual bonus. "Good reason" was defined for executives hired prior to January 1, 2009, to include the ability of the executive to terminate voluntarily for any reason during the 30-day period immediately following the one-year anniversary of the change of control. This type of provision, which was eliminated for executives hired after January 1, 2009, is sometimes called a "modified double-trigger" because payment is made only if there is a change of control and the executive officer's employment is terminated. The agreements prior to January 1, 2009 utilized a modified double-trigger because the Board of Directors believed change-of-control payments only should be made if there is a separation of employment following a change-of-control, but also believed that the right to voluntarily terminate for any reason within 30 days after the first anniversary of the change of control helped ensure that the executive's services would be available during an important transition period. The 2.99 times multiple for change-of-control payments was selected because at the time it was considered standard. Although many companies also include provisions for tax gross-up payments to cover any excise taxes on excess parachute payments, the Board of Directors of the Company decided not to include this additional benefit in the Company's agreements. Instead, under the Company's agreements if the excise tax would be imposed, the change-of-control payments will be reduced to a point where no excise tax would be payable, if such reduction would result in a greater after-tax payment.

The form of Change of Control Agreements and Employment Agreement are filed as Exhibits 10.31, 10.32, 10.33, 10.37 and 10.38 to this Annual Report on Form 10-K.

In addition, pursuant to the terms of the Company's incentive compensation plans, upon a change of control, all stock options will vest immediately and, for a 60-day period following the change of control, executive officers may surrender their options and receive in return a cash payment equal to the excess of the change of control price (as defined) over the exercise price; all performance units will vest and be paid out immediately in cash as if the applicable performance goals had been satisfied at target levels; and any annual incentive award outstanding for the year in which the participant's termination occurs for any reason, other than cause, within 24 months after the change of control will be paid in cash at target level on a prorated basis.

In connection with Mr. Trauschke's appointment in April 2009 as Vice President and CFO, the Company and Mr. Trauschke entered into an employment arrangement, the terms of which are summarized below. The terms of the employment arrangement were approved by the Committee and were subject to arms-length bargaining between Mr. Trauschke and the Company. Under his employment arrangement, Mr. Trauschke's initial annual base salary was set at $382,500 and he received a cash signing bonus of $175,000, payable in two installments, of which $87,500 was paid on April 24, 2009 and $87,500 was paid on August 28, 2009. Mr. Trauschke is obligated under the employment arrangement to repay the $175,000 if he voluntarily resigns or is terminated by the Company for cause within two years of his start date, which was April 24, 2009. Pursuant to the employment arrangement, Mr. Trauschke received an annual award under the Company's Annual Incentive Plan with a target amount of 60 percent of his base salary. Mr. Trauschke also received an award of two grants of performance units under his employment arrangement, both of which are described above. Since Mr. Trauschke's prior employer and residence were in North Carolina, the Company also agreed, under the employment arrangement, to reimburse Mr. Trauschke for various relocation and related expenses, including: (i) travel expenses between North Carolina and Oklahoma City (maximum of one round trip per week) for nine months or, if sooner, the closing of the sale of his house in North Carolina, (ii) expenses for two house hunting trips in the Oklahoma City area for Mr. Trauschke and his wife, (iii) a real estate commission of six percent or less from the sale of his house in North Carolina, within one year of Mr. Trauschke commencing employment, (iv) moving expenses associated with moving his residence and family to Oklahoma City and (v) interim living expenses of up to $3,000 per month for nine months pending the sale of his residence in North Carolina. The Company is obligated under the employment arrangement to pay Mr. Trauschke an amount equal to 1.5 times his then annual rate of base salary if the Company terminates Mr. Trauschke's employment other than for cause before April 24, 2011. After January 1, 2010, all of the provisions of the arrangement with Mr. Trauschke became subject to change by the Company, other than the foregoing provision to pay Mr. Trauschke 1.5 times his salary for termination prior to April 24, 2011, other than for cause.

As noted above, the Company agreed to pay Mr. Trauschke's travel costs of commuting between Oklahoma City and his home in North Carolina, along with his interim living expenses in Oklahoma City and househunting trips with his spouse, for nine months or until the sale of his home in North Carolina. Since the payment of these expenses by the Company is treated as taxable income to Mr. Trauschke, the Company also grossed-up these payments to compensate Mr. Trauschke for the taxes owed, which is consistent with the Company's relocation policy for all employees. In May, June and July 2009, these expenses averaged approximately $8,800 per month, which, when grossed-up for taxes, resulted in a payment by the Company of approximately $13,000 per month. In August 2009 and despite not having sold his house in North Carolina, Mr. Trauschke relocated his family to Oklahoma City and the Company began paying the cost of his rental house in the Oklahoma City area, which was $4,650 per month and substantially less than the $8,800 per month that the Company had been paying Mr. Trauschke for commuting and interim living expenses. Because the $4,650 was taxable to Mr. Trauschke, it was grossed-up for taxes, consistent with the Company's relocation policy for all employees, resulting in a monthly payment by the Company of approximately $6,800. The Company also paid Mr. Trauschke's expenses in moving his family and belongings to Oklahoma City, which aggregated approximately $3,800. Since this amount was not taxable to Mr. Trauschke, it was not grossed-up for taxes. Thus, for 2009, the aggregate amount paid to Mr. Trauschke for relocation and related benefits was approximately $76,450, of which approximately $23,450 represented gross-up payments for taxes. The Committee and the Company believe that this practice of paying actual relocation expenses, including, where applicable, gross-ups for taxes incurred, for newly-hired executives is preferable to paying the executive at hiring a lump sum intended to compensate the executive for relocation expenses. In recognition of Mr. Trauschke's performance in 2009 and the depressed housing market, the Committee at its meeting in December 2009 extended Mr. Trauschke's relocation benefits until the earlier to occur of June 30, 2010, or the sale of his house in North Carolina.

Exhibit 10.40

Amendment No. 1
OGE Energy Corp. Restoration of Retirement Income Plan
(As Amended and Restated Effective January 1, 2005)

OGE Energy Corp., an Oklahoma corporation (the "Company"), in accordance with the authority reserved to the Company under Section 9 of the OGE Energy Corp. Restoration of Retirement Income Plan (As Amended and Restated Effective January 1, 2005) (the "Plan"), hereby amends the Plan, effective as of January 1, 2010, in the following respect:

1. By adding at the end of the definition of "Compensation" in Section 2 of the Plan a new sentence to read as follows:

   "Notwithstanding any provision of the Plan, with respect to any Participant who for the first time becomes a participant in the Retirement Plan on or after January 1, 2010, Compensation shall not, for purposes of Section 5(a) or for any other purpose of the Plan, include any amounts paid to such Participant for any period of service with the Company or other Employer before January 1, 2010 (including any bonus paid in 2010 for such service)."

2. By deleting the first sentence of the first paragraph of Section 5 of the Plan and inserting in lieu thereof a new sentence to read as follows:

   "The benefits payable to a Participant or his beneficiary or beneficiaries under this Plan shall be equal to the excess, if any, of:

   (a) the benefits which would have been paid on or after July 14, 1987, to such Participant, or on his behalf to his beneficiary or beneficiaries, under the Retirement Plan, if the provisions of the Retirement Plan were administered (i) using the definition of Compensation contained in Section 2 of the Plan and (ii) without regard to the 415 Limit or the 401(a)(17) Limit, over

   (b) the benefits which are payable to such Participant, or on his behalf to his beneficiary or beneficiaries, under the Retirement Plan; provided, however, that, with respect to a Participant who for the first time becomes a participant in the Retirement Plan on or after January 1, 2010, the benefit payable under the Retirement Plan shall be determined for purposes of this subsection (b) as if under the Retirement Plan the Participant had accrued no benefits attributable to compensation for any periods of service with the Company or other Employer before January 1, 2010 (including any bonus paid in 2010 for such service)."

3. By deleting the phrase "with the objective that such recipient" where it appears in the first sentence of the second paragraph of Section 5 of the Plan and inserting in lieu thereof the phrase "with the objective that, except as provided in the preceding paragraph, such recipient".

4. Except as provided herein, the Plan remains in full force and effect.

IN WITNESS WHEREOF, OGE Energy Corp. has caused this instrument to be executed in its name by a member of its Benefits Oversight Committee as of the 16th day of December 2009.

OGE ENERGY CORP.

By: Its Benefits Oversight Committee

By: /s/ Carla D. Brockman
Title: Vice President – Administration / Corporate Secretary

Exhibit 10.41

Amendment No. 2 to the
OGE Energy Corp. Deferred Compensation Plan
(As Amended and Restated Effective January 1, 2005)

OGE Energy Corp., an Oklahoma corporation (the "Company"), by action of its Benefits Oversight Committee taken in accordance with the authority granted to it by Article X of the OGE Energy Corp. Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005), as heretofore amended (the "Plan"), hereby further amends the Plan in the following respects effective as of January 1, 2010:

1. By deleting the last two paragraphs of Section 4.4 of the Plan and inserting in lieu thereof new subsections (d), (e) and (f) thereof, to read as follows:

"(d) Notwithstanding the foregoing provisions of this Section 4.4, the Administrator may provide that an individual who becomes an Eligible Employee on his date of hire by the Company and its Affiliates that occurs on or after the first day and prior to December 1 of a Plan Year may make a Deferral Election for such Plan Year within 30 days of becoming an Eligible Employee; provided, however, that such Deferral Election shall relate only to (i) Base Salary paid for the services to be performed after the date such election becomes irrevocable; and/or (ii) the portion of the Bonus relating to the services performed after the election becomes irrevocable, determined by multiplying the total Bonus amount relating to the Plan Year by a ratio of the number of days remaining in such Plan Year after the Deferral Election becomes irrevocable to the total number of days in the Plan Year. Notwithstanding the foregoing, no individual who becomes an Eligible Employee on his date of hire by the Company and its Affiliates that occurs on or after the first day and prior to December 1 of a Plan Year as a result of or in connection with a corporate acquisition, merger or similar transaction shall be eligible to make a Deferral Election under this subsection (d) unless the Administrator determines, consistent with the provisions of Treas. Reg. Section 1.409A-2(a)(7), that the Eligible Employee is not already a participant or eligible to participate in any other nonqualified deferred compensation plan that would be aggregated with the Plan pursuant to Code Section 409A.

(e) Notwithstanding the foregoing provisions of this Section 4.4, the Administrator may provide that an individual who becomes an Eligible Director after the first day of a Plan Year may make a Deferral Election within 30 days of becoming an Eligible Director, which Deferral Election shall relate to Director Compensation paid for services to be performed after the date such election becomes irrevocable.

(f) Once made, a Deferral Election for a Plan Year shall become irrevocable at the end of the Plan Year in which occurs the Election Period during which the Deferral Election was made (or, where applicable, on the last day of the 30-day period described in subsection (d) or (e) above, as the case may be), but such Deferral Election may be changed or revoked prior to that time in accordance with rules established by the Administrator. A Deferral Election which has become irrevocable shall remain in effect for the Plan Year for which made and for subsequent Plan Years unless changed or revoked by the Participant in accordance with rules established by the Administrator. Any such modification or revocation, however, shall be effective beginning for the Plan Year following the Plan Year in which the modification or revocation is filed with the Administrator; provided that, a revocation shall become effective as soon as practicable during the Plan Year in which filed with the Administrator in the event the revocation is required because the Participant obtained a hardship withdrawal under the RSP. If a Deferral Election is revoked during a Plan Year in accordance with the preceding sentence in order for the Participant to obtain a hardship withdrawal under the RSP, the Participant may not make a new Deferral Election before the Election Period established by the Administrator for making deferrals to be effective for the next Plan Year. As of the last day of each Plan Year, a Deferral Election then in effect, shall become irrevocable for the immediately following Plan Year except to the extent modified or revoked as provided above.

IN WITNESS WHEREOF, the Company has caused this instrument to be signed by a duly authorized officer on this 16th day of December, 2009.

OGE ENERGY CORP.

By: /s/ Carla D. Brockman

Exhibit 12.01

OGE ENERGY CORP.
RATIO OF EARNINGS TO FIXED CHARGES

(*In thousands*)	Year Ended Dec 31, 2005	Year Ended Dec 31, 2006	Year Ended Dec 31, 2007	Year Ended Dec 31, 2008	Year Ended Dec 31, 2009
Earnings:					
Pre-tax income from continuing operations	$ 229,838	$ 346,560	$ 360,958	$ 332,594	$ 382,192
Add Fixed Charges	95,957	104,156	97,599	130,023	154,498
Subtotal	325,795	450,716	458,557	462,617	536,690
Subtract:					
Allowance for borrowed funds used during construction	2,233	4,487	3,989	3,950	8,284
Other capitalized interest	---	920	902	3,615	6,336
Total Earnings	323,562	445,309	453,666	455,052	522,070
Fixed Charges:					
Interest on long-term debt	79,951	88,287	88,677	106,565	143,593
Interest on short-term debt and other interest charges	12,571	13,108	6,444	21,041	8,453
Calculated interest on leased property	3,435	2,761	2,478	2,417	2,452
Total Fixed Charges	$ 95,957	$ 104,156	$ 97,599	$ 130,023	$ 154,498
Ratio of Earnings to Fixed Charges	3.37	4.28	4.65	3.50	3.38

Exhibit 21.01

OGE Energy Corp.
Subsidiaries of the Registrant

Name of Subsidiary	Jurisdiction of Incorporation	Percentage of Ownership
Oklahoma Gas and Electric Company	Oklahoma	100.0
Enogex LLC	Oklahoma	100.0
Enogex Gathering & Processing LLC	Oklahoma	100.0
Enogex Products LLC	Oklahoma	100.0
Enogex Gas Gathering LLC	Oklahoma	100.0

The above listed subsidiaries have been consolidated in the Registrant's financial statements. Certain of the Company's subsidiaries have been omitted from the list above in accordance with Rule 1–02(w) of Regulation S-X.

Exhibit 23.01

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statement (Form S-8 No. 333-71327) pertaining to the 1998 stock incentive plan, the Registration Statement (Form S-8 No. 333-92423) pertaining to the deferred compensation plan, the Registration Statement (Form S-8 No. 333-104497) pertaining to the employees' stock ownership and retirement savings plan, the Registration Statement (Form S-8 No. 333-115735) pertaining to the 2003 stock incentive plan, the Registration Statement (Form S-8 No. 333-152022) pertaining to the 2008 stock incentive plan, the Registration Statement (Form S-3ASR No. 333-151780) pertaining to common stock and preferred share purchase rights and the Registration Statement (Form S-3ASR No. 333-155756) pertaining to the dividend reinvestment and stock purchase plan, of our reports dated February 17, 2010, with respect to the consolidated financial statements and schedule of OGE Energy Corp., and the effectiveness of internal control over financial reporting of OGE Energy Corp., included in the Annual Report (Form 10-K) for the year ended December 31, 2009.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 17, 2010

Exhibit 24.01

POWER OF ATTORNEY

WHEREAS, OGE ENERGY CORP., an Oklahoma corporation (herein referred to as the "Company"), is about to file with the Securities and Exchange Commission, under the provisions of the Securities Exchange Act of 1934, as amended, its annual report on Form 10-K for the year ended December 31, 2009; and

WHEREAS, each of the undersigned holds the office or offices in the Company herein-below set opposite his or her name, respectively;

NOW, THEREFORE, each of the undersigned hereby constitutes and appoints PETER B. DELANEY, SEAN TRAUSCHKE and SCOTT FORBES and each of them individually, his or her attorney with full power to act for him or her and in his or her name, place and stead, to sign his name in the capacity or capacities set forth below to said Form 10-K and to any and all amendments thereto, and hereby ratifies and confirms all that said attorney may or shall lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this 17th day of February, 2010.

Peter B. Delaney, Chairman, Principal Executive Officer and Director	/ s / Peter B. Delaney
Wayne H. Brunetti, Director	/ s / Wayne H. Brunetti
Luke R. Corbett, Director	/ s / Luke R. Corbett
John D. Groendyke, Director	/ s / John D. Groendyke
Kirk Humphreys, Director	/ s / Kirk Humphreys
Robert Kelley, Director	/ s / Robert Kelley
Linda P. Lambert, Director	/ s / Linda P. Lambert
Robert O. Lorenz, Director	/ s / Robert O. Lorenz
Leroy C. Richie, Director	/ s / Leroy C. Richie
J. D. Williams, Director	/ s / J. D. Williams
Sean Trauschke, Principal Financial Officer	/ s / Sean Trauschke
Scott Forbes, Principal Accounting Officer	/ s / Scott Forbes

STATE OF OKLAHOMA)
) SS
COUNTY OF OKLAHOMA)

On the date indicated above, before me, Sharon Whiting, Notary Public in and for said County and State, personally appeared the above named directors and officers of OGE ENERGY CORP., an Oklahoma corporation, and known to me to be the persons whose names are subscribed to the foregoing instrument, and they severally acknowledged to me that they executed the same as their own free act and deed.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal on the 17th day of February, 2010.

/s/ Sharon Whiting
Sharon Whiting
Notary Public in and for the County
of Oklahoma, State of Oklahoma

My Commission Expires:
February 17, 2014

Exhibit 31.01

CERTIFICATIONS

I, Peter B. Delaney, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 18, 2010

/s/ Peter B. Delaney

Peter B. Delaney
Chairman of the Board, President and
Chief Executive Officer

Exhibit 31.01

CERTIFICATIONS

I, Sean Trauschke, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 18, 2010

/s/ Sean Trauschke

Sean Trauschke
Vice President and Chief Financial Officer

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

In connection with the Annual Report of OGE Energy Corp. (the “Company”) on Form 10-K for the period ended December 31, 2009, as filed with the Securities and Exchange Commission (the “Report”), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

February 18, 2010

/s/ Peter B. Delaney
Peter B. Delaney
Chairman of the Board, President
and Chief Executive Officer

/s/ Sean Trauschke
Sean Trauschke
Vice President
and Chief Financial Officer

Exhibit 99.01

OGE Energy Corp. Cautionary Factors

The Private Securities Litigation Reform Act of 1995 provides a “safe harbor” for forward-looking statements to encourage such disclosures without the threat of litigation providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements have been and will be made in written documents and oral presentations of the Company. Such statements are based on management’s beliefs as well as assumptions made by and information currently available to management. When used in the Company’s documents or oral presentations, the words “anticipate”, “believe”, “estimate”, “expect”, “intend”, “objective”, “plan”, “possible”, “potential”, “project” and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company’s actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following, by segment:

Consolidated (including Electric Utility, Natural Gas Transportation and Storage, Natural Gas Gathering and Processing and Marketing Segments)

- Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, transmission, currency, interest rate and warranty risks;
- Risks associated with price risk management strategies intended to mitigate exposure to adverse movement in the prices of natural gas on both a global and regional basis, including commodity price changes, market supply shortages, interest rate changes and counterparty default;
- General economic conditions, including the availability of credit, access to existing lines of credit, actions of rating agencies and their impact on our ability to access the capital markets, inflation rates and monetary fluctuations;
- Customer business conditions including demand for their products or services and supply of labor and materials used in creating their products and services currently and in the future;
- Financial or regulatory accounting principles or policies imposed by the Financial Accounting Standards Board, the Securities and Exchange Commission (“SEC”), the Federal Energy Regulatory Commission, state public utility commissions; the regional state committee which regulates the Southwest Power Pool; state entities which regulate natural gas transmission, gathering and processing and similar entities with regulatory oversight;
- Environmental laws, safety laws or other regulations passed by the U.S. Environmental Protection Agency, the Oklahoma Department of Environmental Quality or other governing agencies that may impact the cost of operations or restricts or changes the way the Company operates its facilities;
- Availability or cost of capital, including changes in interest rates, market perceptions of the utility and energy-related industries, the Company or any of its subsidiaries or security ratings;
- Employee workforce factors including changes in key executives and employee retention;
- Social attitudes regarding the utility, natural gas and power industries;
- Identification of suitable investment opportunities to enhance shareowner returns and achieve long-term financial objectives through business acquisitions and divestitures;
- Some future investments made by the Company could take the form of noncontrolling interests which would limit the Company’s ability to control the development or operation of an investment;
- Increased pension and healthcare costs;

- Costs and other effects of legal and administrative proceedings, settlements, investigations, claims and matters, including but not limited to those described in Note 13 of Notes to Consolidated Financial Statements of the Company's Form 10-K for the year ended December 31, 2009, under the caption Commitments and Contingencies;

- Technological developments, changing markets and other factors that result in competitive disadvantages and create the potential for impairment of existing assets; and

- Other business or investment considerations that may be disclosed from time to time in the Company's SEC filings or in other publicly disseminated written documents.

Electric Utility Segment

- Increased competition in the utility industry, including effects of decreasing margins as a result of competitive pressures; industry restructuring initiatives; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, unusual maintenance or repairs; unanticipated changes to fossil fuel, natural gas or coal supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints;

- Rate-setting policies or procedures of regulatory entities, including environmental externalities;

- Approval of future regulatory filings with the Oklahoma Corporation Commission or the Arkansas Public Service Commission; and

- Discontinuance of accounting principles for certain types of rate-regulated activities.

Natural Gas Transportation and Storage and Natural Gas Gathering and Processing Segments

- Increased competition in the natural gas processing industry, including effects of decreasing margins as a result of competitive pressures, commodity exposure and nature of competitors entering the industry; and

- Cold weather extremes that may impact the ability of producing customers to maintain gas deliveries, or the quality of such deliveries, into the pipeline system.

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