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, 2010

OR

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

Commission File Number: 1-12579

OGE ENERGY CORP.

(Exact name of registrant as specified in its charter)

Oklahoma	**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

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). x 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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer x Accelerated Filer o
Non-Accelerated Filer o (Do not check if a smaller reporting company) Smaller reporting company o

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

At June 30, 2010, 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 $3,549,344,792 based on the number of shares held by non-affiliates (97,082,735) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $36.56.

At January 31, 2011, 97,636,311 shares of common stock, par value $0.01 per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2011 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, 2010

TABLE OF CONTENTS

GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations that are found throughout this Form 10-K.

Abbreviation	Definition
401(k) Plan	Qualified defined contribution retirement plan
AEFUDC	Allowance for equity funds used during construction
AFUDC	Allowance for funds used during construction
APBO	Accumulated postretirement benefit obligation
APSC	Arkansas Public Service Commission
ArcLight	ArcLight Energy Partners Fund IV, L.P.
ArcLight affiliate	Bronco Midstream Holdings, LLC, Bronco Midstream Holdings II, LLC, collectively
ARO	Asset retirement obligations
ARRA	American Recovery and Reinvestment Act of 2009
Atoka	Atoka Midstream LLC joint venture
BART	Best Available Retrofit Technology
Bcf	Billion cubic feet
Btu	British thermal unit
Centennial	OG&E's 120 MW wind farm in northwestern Oklahoma
CIP	Critical Infrastructure Protection
Code	Internal Revenue Code of 1986
Company	OGE Energy, collectively with its subsidiaries
Crossroads	OG&E's Crossroads wind project in Dewey County, Oklahoma
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
DRIP/DSPP	Automatic Dividend Reinvestment and Stock Purchase Plan
Dry Scrubbers	Dry flue gas desulfurization units with Spray Dryer Absorber
Dth/day	Decatherms/day
EBITDA	Earnings before Interest, Taxes, Depreciation and Amortization
EHV	Extra High Voltage
Enogex	OGE Enogex Holdings, collectively with its subsidiaries
Enogex LLC	Enogex LLC, collectively with its subsidiaries
Enogex Holdings	Enogex Holdings LLC, the parent company of Enogex LLC and an 86.7 percent owned subsidiary of OGE Energy
Enogex Holdings LLC Agreement	Amended and Restated Limited Liability Agreement of Enogex Holdings
EPA	U.S. Environmental Protection Agency
EPS	Earnings per share
Federal Clean Water Act	Federal Water Pollution Control Act of 1972, as amended
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
FTSA	Firm Transportation Service Agreement
GAAP	Accounting principles generally accepted in the United States
GFB	Guaranteed Flat Bill
GPM	Gallons per million cubic foot
Health Care Reform Acts	Patient Protection and Affordable Care Act of 2009 and Health Care and Education Reconciliation Act of 2010, collectively
IRS	Internal Revenue Service
kV	Kilovolt
kVA	Kilo Volt-Amps
KWH	Kilowatt-hour
Investment Agreement	Agreement pursuant to which ArcLight affiliate agreed to make an initial equity investment in Enogex Holdings
McClain Plant	OG&E's 520 MW natural gas-fired, combined cycle generation facility
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
Medicare Part D Subsidy	Federal subsidy related to certain retiree prescription drug plans that were determined to be actuarially equivalent to the benefit provided under Medicare Part D paid to employers as part of the Medicare Act

Abbreviation	Definition
MEP	Midcontinent Express Pipeline, LLC
MMBtu	Million British thermal unit
MMcf/d	Million cubic feet per day
MW	Megawatt
MWH	Megawatt-hour
Moody’s	Moody’s Investors Services
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NGL	Natural gas liquid
NGPA	Natural Gas Policy Act
NOX	Nitrogen oxide
NYMEX	New York Mercantile Exchange
OCC	Oklahoma Corporation Commission
OER	OGE Energy Resources LLC, wholly-owned subsidiary of Enogex LLC
Off-system sales	Sales to other utilities and power marketers
OG&E	Oklahoma Gas and Electric Company
OGE Holdings	OGE Enogex Holdings, LLC, wholly-owned subsidiary of OGE Energy and parent company of Enogex Holdings
Ongoing Earnings	GAAP net income less charge for Medicare Part D tax subsidy
Ongoing EPS	GAAP EPS less charge for Medicare Part D tax subsidy
OSHA	Federal Occupational Safety and Health Act of 1970
OU Spirit	OG&E’s 101 MW OU Spirit wind farm in western Oklahoma
Pension Plan	Qualified defined benefit retirement plan
PIPES Act	Pipeline Inspection, Protection, Enforcement and Safety Act of 2006
POP	Percent-of-proceeds
POL	Percent-of-liquids
PRM	Price risk management
Products	Enogex Products LLC, wholly-owned subsidiary of Enogex LLC
PSI Act	Pipeline Safety Improvement Act of 2002
PSO	Public Service Company of Oklahoma
PURPA	Public Utility Regulatory Policy Act of 1978
QF	Qualified cogeneration facilities
QF contracts	Contracts with QFs and small power production producers
RCRA	Federal Resource Conservation and Recovery Act of 1976
Redbud Plant	OG&E’s 1,230 MW natural gas-fired, combined-cycle generation facility in Luther, Oklahoma
RFP	Request for proposal
SEC	Securities and Exchange Commission
SERP	Supplemental Executive Retirement Plan
SIP	State implementation plan
SO2	Sulfur dioxide
SOC	Statement of Operating Conditions
SPP	Southwest Power Pool
Standard and Poor’s	Standard and Poor’s Ratings Services
System sales	Sales to OG&E’s customers
TBtu/d	Trillion British thermal units per day
VaR	Value-at-risk
Windspeed	OG&E’s transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma

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 from those expressed in forward-looking statements. In addition to the specific ris k 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, access to the commercial paper markets, actions of rating agencies and their impact on capital expenditures;
- the ability of 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 NGLs, 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;
- whether OG&E can successfully implement its Smart Grid program to install meters for its customers and integrate the Smart Grid meters with its customer billing and other computer information systems;
- advances in technology;
- 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 SEC 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

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 13 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 OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing 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 three business segments: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. Prior to November 1, 2010, OER, whose primary operations are in natural gas marketing, was directly owned by OGE Energy. On November 1, 2010, OGE Energy distributed the equity interests in OER to Enogex LLC. Also, Enogex LLC h olds a 50 percent ownership interest in Atoka. Enogex LLC is a Delaware single-member limited liability company.

On October 5, 2010, OGE Energy entered into an Investment Agreement with the ArcLight affiliate, pursuant to which the ArcLight affiliate agreed to make an initial equity investment in Enogex Holdings, the parent company of Enogex LLC, in an amount equal to $183,150,000 in exchange for a 9.9 percent membership interest in Enogex Holdings. As a result of this transaction, ArcLight acquired an indirect 9.9 percent interest in Enogex LLC and OGE Energy retained a 90.1 percent interest in Enogex LLC. The Investment Agreement provides ArcLight the opportunity to increase its ownership interest by providing equity funding for capital expenditures associated with Enogex's business plan. The transaction closed on November 1, 2010. As of February 1, 2011, the ArcLight group has a 13.3 percent membership i nterest in Enogex Holdings. See "Natural Gas Midstream Operations – Enogex – Overview" for a further discussion.

Company Strategy

The Company's mission is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customers' needs for energy and related services in a safe, reliable and efficient manner. The Company intends to execute its vision by focusing on its regulated electric utility business and unregulated natural gas business. The Company intends to maintain the majority of its assets in the regulated utility business, however, the Company anticipates significant growth opportunities for its natural gas midstream business. The Company's financial objectives include a long-term annual earnings growth rate of five to seven percent on a weather-normalized basis, maintaining a strong credit rating as well as increasing the dividend to meet the Company's dividend payout objectives. 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 is focused on increased investment to preserve system reliability and meet load growth, leverage its advantageous geographic position to develop renewable energy resources for wind generation 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 and deploy newer technology that improves operational, financial and environmental performance. OG&E also is promoting demand-side management programs to encourage more efficient use of electricity. If these initiatives are successful, OG&E believes it may be able to defer the construction or acquisition of any incremental fossil fuel generation capacity until 2020.

Enogex's business plan entails growing its businesses and providing attractive financial returns through efficient operations and effective commercial management of its assets, capturing growth opportunities through expansion projects, increased utilization of existing assets and through acquisitions in and around its footprint. Enogex also plans to continue to increase the percentage that fee-based processing agreements represent of the total processing volumes. In addition, Enogex is seeking to geographically diversify its gathering, processing and transportation businesses principally by expanding into other areas that are complementary with the Company's capabilities. Enogex expects to accomplish this diversification by undertaking organic growth projects and through acquisitions.

The Company's corporate strategy is to continue to maintain the diversified asset position of OG&E and Enogex focused on providing competitive energy products and services to customers primarily in the south central United States. The Company will continue to focus on growing products and services with limited or manageable commodity price exposure. The Company believes that many of the risk management activities, commercial skills and market information available from OER provide value in managing Enogex'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 268 communities and their contiguous rural and suburban areas. At December 31, 2010, three other communities and two rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from OG&E for resale. The service area covers 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 268 communities that OG&E serves, 242 are located in Oklahoma and 26 in Arkansas. OG&E derived 89 percent of its total electric operatin g revenues for the year ended December 31, 2010 from sales in Oklahoma and the remainder from sales in Arkansas.

OG&E's system control area peak demand during 2010 was 6,626 MWs on August 4, 2010. OG&E's load responsibility peak demand was 6,171 MWs on August 4, 2010. As reflected in the table below and in the operating statistics that follow, there were 27.6 million MWH system sales in 2010, 25.9 million MWH system sales in 2009 and 26.8 million MWH system sales in 2008. Variations in system sales for the three years are reflected in the following table:

		2010 vs. 2009		2009 vs. 2008	
Year ended December 31	**2010**	**Increase**	2009	Decrease	2008
System sales – millions of MWHs	**27.6**	**6.6%**	25.9	(3.4)%	26.8

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	**2010**	2009	2008
ELECTRIC ENERGY *(Millions of MWH)*			
Generation (exclusive of station use)	**25.6**	25.0	25.7
Purchased	**4.7**	3.9	4.3
Total generated and purchased	**30.3**	28.9	30.0
Company use, free service and losses	**(2.2)**	(2.0)	(1.8)
Electric energy sold	**28.1**	26.9	28.2
ELECTRIC ENERGY SOLD *(Millions of MWH)*			
Residential	**9.6**	8.7	9.0
Commercial	**6.7**	6.4	6.5
Industrial	**3.8**	3.6	4.0
Oilfield	**3.1**	2.9	2.9
Public authorities and street light	**3.0**	3.0	3.0
Sales for resale	**1.4**	1.3	1.4
System sales	**27.6**	25.9	26.8
Off-system sales	**0.5**	1.0	1.4
Total sales	**28.1**	26.9	28.2
ELECTRIC OPERATING REVENUES *(In millions)*			
Residential	**$ 894.8**	$ 717.9	$ 751.2
Commercial	**521.0**	439.8	479.0
Industrial	**212.5**	172.1	219.8
Oilfield	**162.8**	132.6	151.9
Public authorities and street light	**200.8**	167.7	190.3
Sales for resale	**65.8**	53.6	64.9
Provision for rate refund	**---**	(0.6)	(0.4)
System sales revenues	**2,057.7**	1,683.1	1,856.7
Off-system sales revenues	**21.7**	31.8	68.9
Other	**30.5**	36.3	33.9
Total operating revenues	**$ 2,109.9**	$ 1,751.2	$ 1,959.5
ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)*			
Residential	**670,309**	665,344	659,829
Commercial	**86,496**	85,537	85,030
Industrial	**3,020**	3,056	3,086
Oilfield	**6,418**	6,437	6,424
Public authorities and street light	**16,264**	16,124	15,670
Sales for resale	**51**	52	49
Total	**782,558**	776,550	770,088
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 1,339.81**	$ 1,083.50	$ 1,145.05
Average annual use (KWH)	**14,304**	13,197	13,659
Average price per KWH (cents)	**$ 9.37**	$ 8.21	$ 8.38

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, 2010, 88 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and four 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 f or the protection of utility customers with respect to the FERC jurisdictional rates.

Recent and Pending Regulatory Matters

OG&E OU Spirit Wind Power Project. As previously disclosed, on November 25, 2009, OG&E received an order from the OCC authorizing OG&E to recover from Oklahoma customers the cost to construct OU Spirit, with the rider being implemented on December 4, 2009. In January 2008, OG&E filed with the SPP for an interconnection agreement for the OU Spirit project. On May 29, 2009, OG&E executed an interim interconnection agreement, allowing OU Spirit to interconnect to the transmission grid, subject to certain conditions. On August 27, 2009, the FERC issued an order accepting the interim interconnection agreement, subject to certain conditions, which enabl es OU Spirit to interconnect into the transmission grid. On February 8, 2011, the final interconnection agreement was put in place.

On January 19, 2011, the APSC issued an order finding that (i) OU Spirit is prudent and is in the public's interest and (ii) the $2.1 million of costs associated with OU Spirit from September 1, 2010 through June 30, 2011 should be recovered through the Energy Cost Recovery rider, which is expected to be filed with the APSC by March 15, 2011 (beginning July 1, 2011, OU Spirit costs are expected to be recovered in base rates resulting from OG&E's 2010 Arkansas rate case).

OG&E Renewable Energy Filing. In September 2009, OG&E reached agreements with two developers who are to build two new wind farms, totaling 280 MWs, in northwestern Oklahoma. Under the terms of the agreements, CPV Keenan built a 150 MW wind farm in Woodward County, which was placed in service in December 2010, and Edison Mission Energy is to build a 130 MW facility in Dewey County near Taloga, which is expected to be in service during the second quarter of 2011. 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. OG&E will continue to evaluate renewable opportunities to add to its power-generation portfolio in the future.

On January 19, 2011, the APSC issued an order finding that the 280 MW wind power purchase agreements are prudent and should be recovered through the Energy Cost Recovery rider.

OG&E Windspeed Transmission Line Project. The OCC approved OG&E's request to recover construction costs of up to $218 million, including AFUDC, for Windspeed. Construction costs and AFUDC incurred for Windspeed were $212.3 million. Windspeed was placed into service on March 31, 2010, with the recovery rider being implemented with the first billing cycle in April 2010.

OG&E Long-Term Gas Supply Agreements. In May 2010, the OCC approved OG&E's request for a waiver of the competitive bid rules to allow OG&E to negotiate desired long-term gas purchase agreements. On June 29, 2010, OG&E filed a separate application with the OCC seeking approval of four long-term gas purchase agreements, which would provide a 12-year supply of natural gas to OG&E and account for 25 percent of its currently projected natural gas fuel supply needs over the same time period. On September 26, 2010, OG&E filed a motion with the OCC to dismiss this case. A hearing in this m atter was held on October 7, 2010 and the administrative law judge recommended that the case be dismissed without prejudice. OG&E and the other parties to this matter continue ongoing discussions with the OCC Staff.

OG&E Smart Grid Project. Several provisions of the ARRA relate to issues of direct interest to the Company including, in particular, financial incentives to develop smart grid technology, transmission infrastructure and renewable energy. OG&E received a $130 million grant from the DOE to be used for the Smart Grid program in OG&E's service territory.

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

- Pre-approval for system-wide deployment of smart grid technology and authorization for OG&E to begin recovering the costs of the system-wide deployment of smart grid technology through a rider mechanism that will become effective in accordance with the order approving the settlement agreement;
- OG&E's total project costs eligible for recovery (those costs expended or accrued by OG&E prior to the termination of the period authorized by the DOE as eligible for grant funds) shall be capped at $366.4 million, inclusive of the DOE grant award amount. The Smart Grid project cost includes the cost of implementing the Norman, Oklahoma smart grid pilot program previously authorized by the OCC. Under the terms of the settlement, the Smart Grid project cost would be deemed to represent an investment that is fair, just and reasonable and in the public interest and to be prudent and will be recognized in OG&E's 2013 general rate case;
- To the extent that OG&E's total expenditure for system-wide deployment of smart grid technology during the eligible period exceeds the Smart Grid project cost, OG&E shall be entitled to offer evidence and seek to establish that the excess above the Smart Grid project cost was prudently incurred and any such contention may be addressed in OG&E's 2013 rate case;
- Implementation of the recovery rider would commence with the first billing cycle in July 2010;
- Continued utilization of a return on equity previously approved by the OCC for other various recovery riders;
- The recovery rider shall be designed to collect, on a levelized basis, the revenue requirement associated with the estimated project cost of $357.4 million and shall be subject to a true-up in 2014 after the recovery rider expires, including a true-up for project costs, if any, in excess of $357.4 million but less than the Smart Grid project cost. Any over/under recovery remaining will be passed or credited through OG&E's fuel adjustment clause;
- OG&E guarantees that customers will receive the benefit of certain operations and maintenance cost reductions resulting from the smart grid deployment as a credit to the recovery rider;
- Beginning January 1, 2011, OG&E shall make available the smart grid web portal to all customers having a smart meter. OG&E shall expend funds to educate customers regarding the best use of the information available on the portal. In addition, OG&E shall make available to all customers who do not have internet access the opportunity to receive a monthly home energy report. This report shall be made available, free of charge, to customers eligible for the Company's Low Income Home Energy Assistance Program and/or Senior Citizen program who are without internet service. The incremental costs for web portal access, education and the providing of home energy reports free of charge are to be accumulated as a regulatory asset in an amount up to $6.9 million and recovered in base rates beginning in 2014;
- The stranded costs associated with OG&E's existing meters which are being replaced by smart meters will be accumulated in a regulatory asset and recovered in base rates beginning in 2014; and
- OG&E will file an application with the APSC related to the deployment of smart grid technology by the end of 2010.

On December 17, 2010, OG&E filed an application with the APSC requesting pre-approval for system-wide deployment of smart grid technology and a recovery rider, including a credit for the Smart Grid grant. A procedural schedule has not been established in this matter.

OG&E Crossroads Wind Project. In February 2010, OG&E signed memoranda of understanding for 197.8 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with Crossroads. On July 29, 2010, the OCC approved a settlement that would allow OG&E to build, own and operate the wind farm. The key settlement terms approved by the OCC were:

- Authorization for OG&E to begin recovering the costs of Crossroads through a rider mechanism that will be effective until new rates are implemented after OG&E's 2013 general rate case;
- Continued utilization of a return on equity previously approved by the OCC for other various recovery riders, subject to adjustment in the future to reflect the return on equity authorized in subsequent general rate cases;
- OG&E's capital costs for which it is entitled recovery for a 197.8 MW wind farm are $407.7 million;
- To the extent OG&E's total investment in Crossroads exceeds the amount for which it is entitled recovery, OG&E shall be entitled to offer evidence and seek to establish that the excess amount was prudently incurred and should be included in OG&E's rate base; and
- If the three-year rolling average of Crossroads MWHs of production (including a credit for energy not produced due to curtailments or other events caused by system emergencies, force majeure events, or transmission system issues) falls below 712,844 MWHs, OG&E shall file testimony demonstrating the appropriate operation of Crossroads as part of its fuel cost recovery filing.

Pursuant to the terms of the settlement, OG&E chose to expand Crossroads by an additional 29.7 MWs. As a result of the expansion, the amount of capital costs which OG&E is entitled to recover and the three-year rolling average of MWH production were adjusted to $469.7 million and 819,879 MWHs, respectively. The total projected cost of the 227.5 MW expanded project, including AFUDC, is $450 million, which is below the adjusted recovery amount of $469.7 million. OG&E entered into a turbine supply agreement with Siemens whereby OG&E is to acquire 227.5 MWs of wind turbine generation at a cost in excess of $300 million. OG&E expects Crossroads to be in service by the end of 2011.

OG&E is in the process of entering into an interconnection agreement with the SPP for Crossroads. As part of the multi-study interconnection process, the SPP conducted an interim operational study to determine the impact Crossroads will have on the existing transmission system. The SPP verbally indicated that limited interconnection would be necessary to address system stability limitations. In order to enable full interconnection of Crossroads, OG&E put forth a mitigation proposal, consisting of a system protection relay system, which has recently received all the necessary SPP working group and committee approvals to be implemented. This will allow Crossroads to interconnect at the anticipated 227.5 MWs. & #160;On December 30, 2010, the SPP posted the results of its interim operational study to reflect the SPP approval of the mitigation strategy. OG&E expects a final interconnection agreement to be put in place by the second quarter of 2011.

OG&E 2010 Arkansas Rate Case Filing. On September 28, 2010, OG&E filed a rate case with the APSC requesting a rate increase of $17.7 million, to recover the cost of significant electric system expansions and upgrades, including high-voltage transmission lines and wind energy, that have been completed since the last rate filing in August 2008, as well as rising operating costs. If approved, the targeted implementation date for new electric rates is expected to be during the third quarter of 2011. A hearing in this matter is scheduled for May 24, 2011.

OG&E SPP Cost Tracker. On October 7, 2010, OG&E filed an application with the OCC seeking recovery of the Oklahoma jurisdictional portion of (i) costs associated with transmission upgrades and facilities that have been approved by the SPP in its regional planning processes and constructed by other transmission owners throughout the SPP that have been allocated to OG&E through the FERC-approved transmission rates and (ii) SPP administrative fees. OG&E requested authorization to implement a cost tracker in order to recover from its retail customers the third-party project costs discussed above and to collect its administrative SPP cost assessment levied under Schedule 1A of the SPP open access transmission tariff, which is currently recovered in base rates. OG&E also requested authorization to establish a regulatory asset effective January 1, 2011 in order to give OG&E the opportunity to recover such costs that will be paid but not recovered until the cost tracker is made effective. On February 8, 2011, all parties signed a settlement agreement in this matter which would allow OG&E to begin recovering the incremental transmission costs allocated to OG&E by the SPP for base plan transmission projects built by other transmission owners in the SPP through a recovery rider effective January 1, 2011. OG&E anticipates recovering $1.8 million of incremental revenues in 2011 through the rider. OG&E had requested the inclusion of the incremental SPP administrative fee assessment in the recovery rider. Rather than including these costs in the recovery rider, the stipulating parties agreed to allow OG&E to include the projected 2012 level of the SPP adminis trative fee assessment in its anticipated Oklahoma rate case to be filed in the summer of 2011. A hearing on the settlement is scheduled for February 17, 2011. OG&E expects to receive an order from the OCC in this matter during the second quarter of 2011.

OG&E FERC Transmission Rate Incentive Filing. On October 12, 2010, OG&E submitted to the FERC revised tariff sheets to its open access transmission tariff and to the SPP open access transmission tariff to implement two limited transmission rate incentives. If approved by the FERC, the revised tariff sheets will authorize recovery of 100 percent of all prudently incurred construction work in progress in rate base for specific 345 kV EHV transmission projects to be constructed and owned by OG&E within the SPP's region. In addition, if approved by the FERC, the revised tariff sheets will authorize OG&E to recover 100 percent of all prudently incurred development and construct ion costs if the transmission projects are abandoned or cancelled, in whole or in part, for reasons beyond OG&E's control. On December 30, 2010, the FERC granted these two incentives for the Priority Projects discussed below. Also, OG&E plans to make a filing with the FERC in February 2011 to seek incentives for at least five other projects.

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

There are several studies currently under review at the SPP including a 20-year plan to address issues of regional and interregional importance. The 20-year plan suggests overlaying the SPP footprint with a 345 kV transmission system and integrating it with neighboring regional entities. In 2009, the SPP Board of Directors approved a new report that recommended restructuring the SPP's regional planning processes to focus on the construction of a robust transmission system, large enough in both scale and geography, to provide flexibility to meet the SPP's future needs. OG&E expects to actively participate in the ongoing study, development and transmission growth that may result from the SPP's plans.

In 2007, the SPP notified OG&E to construct 44 miles of a new 345 kV transmission line which will originate at OG&E's existing Sooner 345 kV substation and proceed generally in a northerly direction to the Oklahoma/Kansas Stateline (referred to as the Sooner-Rose Hill project). At the Oklahoma/Kansas Stateline, the line will connect to the companion line being constructed in Kansas by Westar Energy. Construction of the line is expected to begin in mid-2011 and the line is estimated to be in service by June 2012.

In January 2009, OG&E received notification from the SPP to begin construction on 50 miles of a new 345 kV transmission line and substation upgrades at OG&E's Sunnyside substation, among other projects. In April 2009, Western Farmers Electric Cooperative assigned to OG&E the construction of 50 miles of line designated by the SPP to be built by Western Farmers Electric Cooperative. The new line will extend from OG&E's Sunnyside substation near Ardmore, Oklahoma, 123.5 miles to the Hugo substation owned by Western Farmers Electric Cooperative near Hugo, Oklahoma. OG&E began preliminary line routing and acquisition of rights-of-way in June 2009. Construction began in January 2011. When construction is completed, which is expected in April 2012, the SPP will allocate a portion of the annua l revenue requirement to OG&E customers according to the regional cost allocation mechanism as provided in the SPP tariff for application to such improvements.

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

On April 27, 2010, the SPP approved, contingent upon approval by the FERC of a regional cost allocation methodology filed with the FERC by the SPP, a set of transmission projects titled "Priority Projects." The Priority Projects consist of several transmission projects, two of which have been assigned to OG&E. The 345 kV projects include: (i) construction of 92 miles of transmission line from OG&E's Woodward District EHV substation to a companion transmission line to be built by Southwestern Public Service to its Hitchland substation in the Texas Panhandle at a cost of $180 million for OG&E, which is expected to be in service by June 2014 and (ii) construction of 80 miles of transmission line from OG&E's Woodward District EHV substation to a companion transmission line at the Kansas border to be built by either Mid-Kansas Electric Company or another company assigned by Mid-Kansas Electric Company at a cost of $135 million to OG&E, which is expected to be in service by December 2014. On June 17, 2010, the FERC approved the cost allocation filed by the SPP and notices to construct these Priority Projects were issued by the SPP on June 30, 2010. On September 27, 2010, OG&E responded to the SPP that OG&E will construct the Priority Projects discussed above beginning in June 2012. The scope of the Woodward District EHV substation/Kansas border Priority Project was subsequently revised and the SPP Board of Directors approved this revision in October 2010. The SPP issued a revised notice to construct for this Priority Project on November 22, 2010. On February 4, 2011, OG&E responded to the SPP that OG&E will construct the revised Priority Project.

The capital expenditures related to the Sooner-Rose Hill, Sunnyside-Hugo, Balanced Portfolio 3E and Priority 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 – Liquidity and Capital Resources – Future Capital Requirements and Financing Activities."

See Note 15 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, 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, 2010 and 2009, OG&E had regulatory assets of $495.3 million and $451.4 million, respectively, and regulatory liabilities of $243.9 million and $363.0 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 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 Renewable Energy Credit 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 option a possible choice in meeting the renewable energy needs of our conservation-minded customers. 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 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.

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 the actual cost of fuel. 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. A second tariff rate option provides a "renewable energy" resource to OG&E's Arkansas retail customers. This renewable energy resource is a Renewable Energy Credit purchase program and is availab le as a voluntary option to all of OG&E's Arkansas retail customers. OG&E's ownership and access to wind resources makes the renewable option a possible choice in meeting the renewable energy needs of our conservation-minded customers. 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 2010, 55 percent of the OG&E-generated energy was produced by coal-fired units, 42 percent by natural gas-fired units and three percent by wind-powered units. Of OG&E's 6,531 total MW capability reflected in the table under Item 2. Properties, 3,834 MWs, or 58.7 percent, are from natural gas generation, 2,476 MWs, or 37.9 percent, are from coal generation and 221 MWs, or 3.4 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, was as follows:

Year ended December 31 *(In KWH - cents)*	**2010**	2009	2008	2007	2006
Coal	**1.911**	1.747	1.153	1.143	1.114
Natural gas	**4.638**	3.696	8.455	6.872	6.829
Weighted average	**3.012**	2.474	3.337	3.173	3.003

The increase in the weighted average cost of fuel in 2010 as compared to 2009 was primarily due to higher natural gas prices and increased natural gas generation. 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. 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. A portion of these fuel costs is included in the base rates to customers and differs for each jurisdiction. The portion o f 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 2,476 MWs, are designed to burn low sulfur western sub-bituminous coal. OG&E purchases coal primarily under contracts expiring in years 2011 and 2015. In 2010, OG&E purchased 9.3 million tons of coal from various Wyoming suppliers. The combination of all coal has a weighted average sulfur content of 0.26 percent and can be burned in these units under existing Federal, state and local environmental standards (maximum of 1.2 lbs. of 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 0.6 lbs. of SO2 per MMBtu, well within the limitations of the current provisions of the Federal Clea n Air Act discussed in Note 14 of Notes to Consolidated Financial Statements. As discussed, in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations," there is a possibility that these emission limits could become more stringent in the future.

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 2010, OG&E issued an RFP for gas supply purchases for periods from November 2010 through March 2011. The gas supply purchases from January through March 2011 account for 21 percent of OG&E's projected 2011 natural gas requirements. The RFP process was completed in September 2010. The contracts resulting from this RFP are tied to various gas price market indices that will expire in 2011. Additional gas supplies to fulfill OG&E's remaining 2011 natural gas requirements will be acquired through additional RFPs in early to mid-2011, 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, 2010, OG&E had 1.4 million MMBtu's in natural gas storage valued at $5.6 million.

Wind

OG&E's current wind power portfolio includes: (i) the Centennial wind farm, (ii) the OU Spirit wind farm, (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 and (iv) access to up to 150 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with CPV Keenan that expires in 2030. During the second quarter of 2011, OG&E also is expected to have access to a 130 MW facility being built by Edison Mission Energy in Dewey County near Taloga. OG&E's

agreement with Edison Mission energy is a 20-year power purchase agreement. Additionally, on July 29, 2010, the OCC approved a settlement that would allow OG&E to build, own and operate 227.5 MWs of wind turbine generators for Crossroads, which is expected to be in service by the end of 2011.

On January 5, 2010, OG&E received an order from the OCC approving the CPV Keenan and Edison Mission Energy power purchase agreements and authorizing OG&E to recover the costs of the power purchase agreements through OG&E's fuel adjustment clause. OG&E will continue to evaluate renewable opportunities to add to its power-generation portfolio in the future.

Safety and Health Regulation

OG&E 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. 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 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 MIDSTREAM OPERATIONS - ENOGEX

Overview

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing 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 three business segments: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. On November 1, 2010, OGE Energy distributed equity interests in its natural gas marketing subsidiary, OER, to Enogex LLC.

On October 5, 2010, OGE Energy entered into an Investment Agreement with the ArcLight affiliate, pursuant to which the ArcLight affiliate agreed to make an initial equity investment in Enogex Holdings in an amount equal to $183,150,000 in exchange for a 9.9 percent membership interest in Enogex Holdings. As a result of this transaction, ArcLight acquired an indirect 9.9 percent interest in Enogex LLC and OGE Energy retained a 90.1 percent interest in Enogex LLC. The Investment Agreement provides ArcLight the opportunity to increase its ownership interest by providing equity funding for capital expenditures associated with Enogex's business plan.

The transaction closed on November 1, 2010. OGE Energy and the ArcLight affiliate have agreed to indemnify each other for breaches of representations, warranties and covenants contained in the Investment Agreement, and, in the case of OGE Energy, for certain tax matters related to the Company, in each case subject to customary thresholds and survival periods.

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

Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. Specifically, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings. In February 2011, OGE Energy and the ArcLight group made contributions of $8.0 million and $71.6 million, respectively, to fund a portion of Enogex LLC's 2011 capital requirements. Also, on February 1, 2011, OGE Energy sold an additional 0.1 percent membership interest in Eno gex Holdings to the ArcLight affiliate for $1.9 million. As a result of these transactions, the ArcLight group has a 13.3 percent membership interest in Enogex Holdings. Until the beginning of 2012, the per unit equity price to be paid will be equal to the initial price that had been paid by ArcLight under the Investment Agreement. On and after January 1, 2012, the equity price per unit will be based on the equity value of Enogex Holdings. Subject to certain adjustments, including for material acquisitions, equity value will be calculated as 9.0 or 9.5 times trailing 12-month EBITDA, depending on the ArcLight group's ownership interest and whether the project has already been identified by Enogex Holdings.

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover the members' respective anticipated tax liabilities plus $12.5 million, to be distributed in proportion to each member's percentage ownership interest. As discussed previously, OGE Holdings has the option to fund between 10 percent and 50 percent of Enogex LLC's capital expenditures which partially or entirely offset the quarterly distributions received.

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

Transportation and Storage

General

Enogex owns and operates 2,285 miles of intrastate natural gas transportation pipelines with 1.72 TBtu/d of average daily throughput during 2010. Enogex also owns and operates two underground storage facilities currently being operated at a working gas level of 24 Bcf. Enogex provides fee-based firm and interruptible transportation services on both an intrastate basis and pursuant to Section 311 of the 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 co ntracts, 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, Cana/Woodford Shale play and the Colony Wash play in western Oklahoma and the Granite Wash play in the Wheeler County, Texas area, which is located in the Texas Panhandle). At December 31, 2010, Enogex was connected to 13 third-party natural gas pipelines and had 63 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, Ques t Pipelines (KPC), Ozark Gas Transmission, L.L.C., Gulf Crossings Pipeline Company LLC and MEP. Further, Enogex is connected to 34 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 24 Bcf and have 650 MMcf/d of maximum withdrawal capability and 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 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 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 p rovided notice of termination 180 days prior to May 1, 2011, the contract will remain in effect at least through April 30,

2012. 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 natural gas-fired electric generation facilities to serve residential and commercial electricity requirements. In 2010, 2009 and 2008, revenues from Enogex's firm intrastate transportation and storage contracts were $116.6 million, $116.8 million and $104.4 million, respectively, of which $47.5 million in each year was attributed to OG&E and $15.3 million in each year was attributed to PSO. Revenues fro m Enogex's firm intrastate transportation and storage contracts represented 28 percent of Enogex's consolidated gross margin in 2010, 33 percent in 2009 and 26 percent in 2008.

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 abili ty 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 five years (previously a triennial requirement). 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.&# 160; 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 Enogex's 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. 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. A final settlement was filed with the FERC on August 5, 2010 and an order is pending. 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 (i) approving the MEP project including the approval of a limited jurisdiction certificate and (ii) authorizing the Enogex lease agreement with MEP. Accordingly, Enogex proceeded with the construction of facilities necessary to implement this service. On August 25, 2008, a 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. On December 28, 2010, the Court of Appeals issued an opinion generally upholding the FERC's orders, but remanding the case for further explanation of one aspect of the FERC's reasoning. The Court of Appeals emphasized that it was not vacating the FERC's orders and that its approval of the Enogex lease agreement with MEP remains in effect and legally binding. On remand, the FERC must clarify that its decision was based on a finding that the lease does not adversely affect existing customers on Enogex's system. Enogex anticipates that the FERC will issue an order on remand in the first half of 2011. On January 21, 2011, Apache Corporation filed a motion asking the FERC to establish procedures on remand and to either condition the lease on Enogex's willingness to provide firm Section 311 transportation service to existing customers on all portions of its system or to establish an expedited briefing schedule. On February 7, 2011, Enogex, MEP and Chesapeake Energy Corporation filed a joint answer asking the FERC to find, among other things, that the reduction in the amount of interruptible transportation capacity available due to the MEP lease did not have an adverse affect on Apache Corporation and to acknowledge that Apache Corporation's request to condition the lease on the provision of West Zone 311 firm transportation service has been addressed as Enogex filed a rate case on January 28, 2011 proposing to implement such service effective March 1, 2011.

Enogex FERC Section 311 2009 Rate Case

On March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for its new firm East Zone Section 311 transportation service and to revise the rates for its existing East and West Zone interruptible Section 311 transportation service. In anticipation of offering this new service, Enogex had filed with the FERC, as required by the FERC's regulations, a revised SOC Applicable to Transportation Services to describe the terms, conditions and operating arrangements for the new service. Enogex made the SOC filing on February 27, 2009. Enogex began offering firm East Zone Section 311 transportation service on April 1, 2009. The revised East and West Zone zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for the firm East Zo ne 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. On January 4, 2010, the FERC Staff submitted an offer proposing various adjustments to Enogex's filed cost of service. On April 27, 2010, Enogex submitted comments to the FERC Staff stating that it would agree to the offer, contingent upon all parties agreeing to support or not oppose. Parties have until March 16, 2011 to submit comments stating whether they support, or do not oppose, the FERC Staff's offer.

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 based on the value of the fuel at the time of usage.

In April 2010, the FERC accepted Enogex's proposed zonal fixed fuel percentages.

Enogex Mid-Year 2010 Fuel Filing

As Enogex anticipated over recovering fuel for the remainder of 2010, Enogex filed a mid-year fuel filing on July 1, 2010. The proposed reduced rates were effective August 1, 2010 and were subject to refund pending FERC approval. Concurrently, Enogex asked the FERC for authority to change the timing of its annual filing to February 15 and for implementation of a new fuel year with a 12-month period of April 1 through March 31. If both requests are approved, the reduced rates will remain in effect until March 31, 2011, at which time new rates for the period from April 1, 2011 to March 31, 2012 will be implemented. On November 23, 2010, the FERC issued an order accepting Enogex's revised fuel factors and approving revisions to the timing of the annual fuel filing to February 15 and for implementation of a new fuel year with a 12-month period of April 1 through March 31. No refund was required as a result of the revised fuel percentages.

Enogex Storage SOC Filing

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

Enogex FERC Section 311 2011 Rate Case

On January 28, 2011, Enogex submitted a new rate filing at the FERC to set the maximum rate for a new firm Section 311 transportation service in the West Zone of its system and to revise the currently effective maximum rates for Section 311 interruptible transportation service in the East Zone and West Zone. Along with establishing the rate for a new firm service in the West Zone, Enogex's filing requested a decrease in the maximum interruptible zonal rates in the West Zone and to retain the currently effective rates for firm and interruptible services in the East Zone. Enogex reserved the right to implement the higher rates for firm and interruptible services in the East Zone supported by the cost of service to the extent an expeditious settlement agreement cannot be reached in the proceeding. Enogex proposed that the rates be placed into effect on March 1, 2011. Contemporaneous with the rate filing, Enogex submitted a motion to defer the deadline for protests until April 4, 2011 to facilitate expedited settlement negotiations. The regulations provide that the FERC has 150 days to act on the filing but also permit the FERC to issue an order extending the time period for action. No action has yet been taken by the FERC.

Other

Certain of Enogex's pipeline operations are subject to various state and Federal safety and environmental and pipeline transportation laws. For example, the DOT has adopted regulations requiring pipeline operators to develop integrity management programs for its applicable pipelines. During 2010, Enogex incurred $26.9 million of capital expenditures and operating costs for pipeline integrity management. Enogex currently estimates that it will incur capital expenditures and operating costs of between $100 million and $150 million from 2011 and 2015 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, Enoge x 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 43 miles of 24-inch steel pipe in Woods and Major counties in Oklahoma, and added 24,000 horsepower of electric-driven co mpression in Bennington, Oklahoma**.** Enogex's capital expenditures allocated to its support of the MEP lease agreement were $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 added an incremental 17,200 horsepower of gas turbine compression at its Bennington compressor station, as well as other system upgrades. These projects were placed into service in December 2010 and January 2011. The capital expenditures associated with these projects were $27 million.

In August 2010, Enogex completed construction of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Aid in Construction payments of $36.7 million received in excess of construction costs were recognized as Deferred Revenues on the Company's Consolidated Balance Sheet and are being amortized on a straight-line basis of $1.2 million per year over the life of the related FTSA under which service is expected to commence in June 2011.

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 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 gat hering 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 5,903 miles of natural gas gathering pipelines with 1.32 TBtu/d of average daily gathered volumes during 2010. Enogex owns and operates eight natural gas processing plants, with a current total inlet capacity of 823 MMcf/d, has a 50 percent interest in and operates the Atoka natural gas processing plant with an inlet capacity of 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, 2010, Enogex extracted and sold 688 million gallons of NGLs.

Enogex gathers and processes natural gas pursuant to a variety of arrangements generally categorized as fee-based, POP, POL and keep-whole arrangements. POP, POL and keep-whole arrangements involve varying levels of 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, 2010, these arrangements accounted for 29 percent of Enogex's natural gas processed volumes.

- *POP and POL 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 POP arrangements and in which Enogex receives proceeds from the sa le of NGLs or the NGLs themselves as compensation for its processing services as POL arrangements. Under POP arrangements, Enogex's margin correlates directly with the prices of natural gas and NGLs. Under POL arrangements, Enogex's margin correlates directly with the prices of NGLs. At December 31, 2010, these arrangements accounted for 40 percent of Enogex's natural gas processed volumes.

- *Keep-Whole Arrangements*. Enogex processes raw natural gas to extract NGLs and returns to the producer the full gas equivalent 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, 2010, these arrangements accounted for 31 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 otherwi se would be required to replace.

Of the commercial grade propane produced at Enogex's processing plants, 12 percent 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 western Oklahoma and 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 system of Enogex provides gas routing flexibility for Enogex to optimize the economics of its gas processing and to improve system utilization and reliability.

In order to meet the growing requirements of its customers, Enogex continues to evaluate the need to expand its processing capabilities on the "super-header" gathering system, such as the 200 MMcf/d processing plant in Canadian County currently under construction.

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., Apache Corporation, Devon Energy Production Company, L.P., BP America Production Company and Samson Resources Company. During 2010, these five c ustomers accounted for 19.7 percent, 13.1 percent, 11.3 percent, 4.6 percent and 3.8 percent, respectively, of Enogex's gathering and processing volumes. During 2010, Enogex's top 10 natural gas producer customers accounted for 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 Chesapeake Mi dstream 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 i t 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, known as the lost and unaccounted for gas bill, which 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 regulations nor the lost and unaccounted for gas bill 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 Cana/Woodford Shale play and the Colony Wash play in western Oklahoma and the Granite Wash play in western Oklahoma and 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 in 2010 or scheduled for completion in 2011 and 2012.

Enogex has constructed a new compressor station in Coal County, Oklahoma, as well as 10 miles of gathering pipe and related treating facilities. The station is designed to accommodate up to 6,700 horsepower of low pressure compression and is supported by five miles of 20-inch steel pipe and five miles of 12-inch steel pipe. The new compressor station also includes the purchase of associated gas treating facilities for the incremental gas in this area. The initial 5,400 horsepower at the compressor station, and the gathering pipe, are currently in service. The treating facilities were placed into service in January 2011. The capital expenditures for this project were $23 million.

In order to gather additional volume in southeast Oklahoma, Enogex constructed an additional low pressure compressor station in Pittsburg County, Oklahoma. This station includes 5,400 horsepower of compression, together with leased treating facilities. The station was fully operational in December 2010. The capital expenditures associated with this project were $12 million.

Western Oklahoma / Texas Panhandle Expansions

Enogex expanded its gathering infrastructure in the Wheeler County, Texas area with the construction of 16 miles of 10-inch steel pipe, as well as the addition of 5,400 horsepower of compression, which became operational and were placed in service during the third quarter of 2010. The capital expenditures associated with this project were $14 million.

Enogex has constructed 38 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 was constructed in phases, with all segments placed in service in December 2010. The capital expenditures associated with this project were $19 million.

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

Enogex is in the process of constructing a new 200 MMcf/d cryogenic processing plant in Canadian County, Oklahoma. The new plant, which will have inlet and residue compression and will be supported by the installation of 31 miles of 20-inch gathering pipeline, as well as 11 miles of 24-inch transmission pipeline providing takeaway capacity from the plant tailgate, is expected to be in service by November 2011. The capital expenditures associated with this project are expected to be $128 million.

Enogex purchased a 200 MMcf/d natural gas processing plant that will be installed in Wheeler County, Texas. This plant will initially add another 120 MMcf/d of processing capacity to Enogex's system with the ability to increase to its full capacity of 200 MMcf/d with the installation of additional residue compression facilities at a later date. The new plant, which will be supported by the installation of 9,400 horsepower of field compression, is expected to be in service in the second quarter of 2012. The capital expenditures associated with this project are expected to be $125 million.

Enogex is in the process of expanding its gathering infrastructure including the addition of low pressure compression and gathering pipe. The expansion is planned to occur in phases, with the initial phase calling for the installation of 35,000 horsepower of low pressure compression and over 120 miles of gathering pipe across three counties in western Oklahoma. This infrastructure is expected to be completed by the second quarter of 2012. The capital expenditures associated with the initial phase of the expansion are expected to be $167 million.

Cox City Plant Fire

On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. Gas volumes normally processed at the Cox City plant were diverted to other facilities or bypassed around Enogex's system to accommodate production and all of the impacted gathered volumes were back online in December. The 120 MMcf/d train previously slated for installation of a cryogenic processing plant at the Wheeler County, Texas location will now be installed at the existing Cox City plant site to bring the facility back to full capacity. The replacement of the damaged train is expected to return the facility back to full service during the third quarter of 2011. Enoge x is currently developing an estimate of the total costs necessary to return the facility back to full service and anticipates the majority of cost beyond the $10 million deductible will be reimbursed by insurance.

Safety and Health Regulation

Certain of Enogex's facilities are subject to pipeline transportation regulations, including the PSI Act and the PIPES Act. The Pipeline Hazardous Materials Safety Administration regulates safety requirements in the design, construction, operation and maintenance of applicable natural gas and hazardous liquid pipeline facilities. Both the PSI Act and the PIPES Act 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 PSI Act 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 ad ministered 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, flamma ble 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

General

OER 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 OER's business on Enogex's system. OER 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.

OER primarily participates in both intermediate-term markets (less than three years) and short-term "spot" markets for natural gas. Although OER 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. OER's average daily sales volumes increased from 0.4 Bcf in 2009 to 0.5 Bcf in 2010. OER'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 OER by buying and selling natural gas futures contracts on the NYMEX 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 VaR limits of $1.5 million in accordance with corporate policies.

Competition

OER 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, 2010, 60.8 percent of OER's service volumes were with electric utilities, local gas distribution companies, pipelines and producers, of which 28.2 percent was with affiliates of OER. The remaining 39.2 percent of service volumes were to marketers, municipals, cooperatives and industrials. At December 31, 2010, 60 percent of the payment exposure was to companies having investment grade ratings with Standard & Poor's. The remaining 40 percent of OER's exposure is with privately held companies, municipals or cooperatives that were not rated by Standard & Poor's. OER applies internal credit analyses and policies to these non-rated companies. At December 31, 2010, all but $1.9 million of OER's exposure was to counterpartie s who were investment grade or deemed investment grade equivalents based upon OER's internal credit analyses.

Regulation

The price at which OER 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, OER is required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission. The FERC and Commodity Futures Trading Commission 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 OER 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 matters. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way they can handle or dispose of their wastes, requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. 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. 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. OG&E and Enogex cannot assure that future events, such as changes in existing laws, the promulgation of new laws or regulations, or the development or discovery of new facts or conditions will not cause them to incur significant costs. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

Of the Company's capital expenditures budgeted for 2011, $9.1 million are to comply with environmental laws and regulations, of which $7.1 million and $2.0 million are related to OG&E and Enogex, respectively. Of the Company's capital expenditures budgeted for 2012, $6.9 million are to comply with environmental laws and regulations, of which $4.9 million and $2.0 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 $28.8 million and $6.8 million, respectively, in 2011 as compared to $22.8 million and $5.0 million, respectively, in 2010.

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 or install emission control equipment. 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.

Climate Change

In 2010, the EPA issued rules requiring permits and greenhouse gas emission limits at certain new sources and certain existing sources that are being modified. At this time, it is not anticipated that the current rules will cause a significant impact to OG&E or Enogex, but 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.

Hazardous Waste

OG&E's and Enogex's operations generate hazardous wastes that are subject to the 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 and occasional larger quantities from periodic power generation related activities. These wastes are treated, stored and disposed at facilities that are permitted to manage them. In 2010, the EPA proposed rules that could make the management of coal ash more costly.

For Enogex, RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. 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. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

Site Remediation

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 and comparable state laws impose liability, without regard to the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Because OG&E and Enogex utilize various products and generate wastes that are considered hazardous substances for purposes of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, OG&E and Enogex could be subject to 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 a significant impact to OG&E or Enogex.

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. Existing water intake structures will be regulated under the Federal Clean Water Act to address imp ingement and entrainment of aquatic organisms.

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 Notes 1 and 14 of Notes to Consolidated Financial Statements.

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, 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 Resources" for a discussion of the Company's capital requirements.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2011 through 2016 are shown in the following table. 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.

(In millions)	2011	2012	2013	2014	2015	2016
OG&E Base Transmission	$ 50	$ 30	$ 20	$ 20	$ 20	$ 20
OG&E Base Distribution	240	200	200	200	200	200
OG&E Base Generation	95	80	70	70	70	70
OG&E Other	45	30	30	30	30	30
Total OG&E Base Transmission, Distribution, Generation and Other	430	340	320	320	320	320
OG&E Known and Committed Projects:						
Transmission Projects:						
Sunnyside-Hugo (345 kV)	150	20	---	---	---	---
Sooner-Rose Hill (345 kV)	35	15	---	---	---	---
Balanced Portfolio 3E Projects	50	170	140	30	---	---
SPP Priority Projects (A)	10	60	155	90	---	---
Total Transmission Projects	245	265	295	120	---	---
Other Projects:						
Smart Grid Program (B)	70	70	25	30	10	10
Crossroads	250	30	---	---	---	---
System Hardening	20	---	---	---	---	---
Total Other Projects	340	100	25	30	10	10
Total OG&E Known and Committed Projects	585	365	320	150	10	10
Total OG&E (C)	1,015	705	640	470	330	330
Enogex LLC Base Maintenance	80	40	40	40	40	40
Enogex LLC Known and Committed Projects:						
Western Oklahoma / Texas Panhandle Gathering Expansion	275	115	20	90	5	15
Other Gathering Expansion	25	25	20	20	20	20
Total Enogex LLC Known and Committed Projects (D)	380	180	80	150	65	75
OGE Energy	25	25	25	25	25	25
Total capital expenditures	$ 1,420	$ 910	$ 745	$ 645	$ 420	$ 430

(A) On February 4, 2011, OG&E responded to the SPP that OG&E will construct the revised Priority Project as discussed in Note 15 of Notes to Consolidated Financial Statements.
(B) These capital expenditures are net of the Smart Grid $130 million grant approved by the DOE.
(C) The capital expenditures above exclude any environmental expenditures associated with 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 NOX burners and related equipment at the three affected generating stations. Preliminary estimates indicate the cost will be $100 million (plus or minus 30 percent). For further information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations."
(D) These capital expenditures represent 100 percent of Enogex LLC's capital expenditures, of which a portion will be funded by the ArcLight group. In February 2011, OGE Energy and the ArcLight group made contributions of $8.0 million and $71.6 million, respectively, to fund a portion of Enogex LLC's 2011 capital requirements. Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. Specifically, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets and at Enogex, will be evaluated based upon their impact upon achieving the Company's financial objectives. The capital expenditure projections related to Enogex Holdings in the table above reflect base market conditions at February 16, 2011 and do not reflect the potential opportunity for a set of growth projects that could materialize.

Pension and Postretirement Benefit Plans

During each of 2010 and 2009, the Company made contributions to its Pension Plan of $50 million to help ensure that the Pension Plan maintains an adequate funded status. During 2011, the Company may contribute up to $50 million to its Pension Plan. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Future Capital Requirements and Financing Activities" for a discussion of the Company's pension and postretirement benefit plans.

Common Stock Dividends

As discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Future Capital Requirements and Financing Activities," at the Company's December 2010 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 $0.3750 per share from $0.3625 per share effective with the Company's first quarter 2011 dividend.

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 DRIP/DSPP or other offerings will be adequate over the next three years to meet anticipated cash needs and to fund future growth opportunities. Additionally, the Company will have an additional source of funding for growth opportunities at Enogex through the ArcLight group. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $145.0 million and $175.0 million at December 31, 2010 and 2009, respectively. At December 31, 2010, Enogex LLC had $25.0 million in outstanding borrowings under its revolving credit agreement with no outstanding borrowings at December 31, 2009. As Enogex LLC's credit agreement matures on March 31, 2013 along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Consolidated Balance Sheets. At December 31, 2010, the Company had $1,064.7 million of net avai lable liquidity under its revolving credit agreements. 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, 2011 and ending December 31, 2012. See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity. At December 31, 2010, the Company had $2.3 million in cash and cash equivalents.

Expected Issuance of OG&E Long-Term Debt

OG&E expects to issue between $250 million and $300 million of long-term debt in mid-2011, 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 $13 million and $15 million in its DRIP/DSPP in 2011. See Note 9 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

Minimum Quarterly Distributions by Enogex Holdings

As discussed in Note 2 of Notes to Consolidated Financial Statements, pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover the members' respective anticipated tax liabilities plus $12.5 million, to be distributed in proportion to each member's percentage ownership interest. As discussed previously, OGE Holdings has the option to fund between 10 percent and 50 percent of Enogex LLC's capital expenditures which partially or entirely offset the quarterly distributions received.

EMPLOYEES

The Company and its subsidiaries had 3,416 employees at December 31, 2010.

EXECUTIVE OFFICERS

The following persons were Executive Officers of the Registrant as of February 17, 2011:

Name	Age	Title
Peter B. Delaney	57	Chairman of the Board and Chief Executive Officer - OGE Energy Corp.
Danny P. Harris	55	President and Chief Operating Officer - OGE Energy Corp.
Sean Trauschke	43	Vice President and Chief Financial Officer - OGE Energy Corp.
Patricia D. Horn	52	Vice President - Governance, Environmental, Health & Safety; Corporate Secretary - OGE Energy Corp.
Gary D. Huneryager	60	Vice President - Internal Audits - OGE Energy Corp.
S. Craig Johnston	50	Vice President - Strategic Planning and Marketing - OGE Energy Corp.
Jesse B. Langston	48	Vice President - Utility Commercial Operations - OG&E
Jean C. Leger, Jr.	52	Vice President - Utility Operations - OG&E
Cristina F. McQuistion	46	Vice President - Process and Performance Improvement - OGE Energy Corp.
Stephen E. Merrill	46	Vice President - Human Resources - OGE Energy Corp.
E. Keith Mitchell	48	Senior Vice President and Chief Operating Officer - Enogex LLC
Howard W. Motley	62	Vice President - Regulatory Affairs - OG&E
Reid V. Nuttall	53	Vice President - Chief Information Officer - OGE Energy Corp.
Melvin H. Perkins, Jr.	62	Vice President - Power Delivery - OG&E
Paul L. Renfrow	54	Vice President - Public Affairs - OGE Energy Corp.
William J. Bullard	62	General Counsel - OG&E; Assistant General Counsel - OGE Energy Corp.
Scott Forbes	53	Controller and Chief Accounting Officer - OGE Energy Corp.
Max J. Myers	36	Treasurer - OGE Energy Corp.
Jerry A. Peace	48	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, Forbes, Myers and Peace and Ms. Horn and Ms. McQuistion are also officers of OG&E. Messrs. Delaney, Harris, Trauschke and Myers and Ms. Horn are also officers of Enogex Holdings and/or its subsidiaries. Each officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Shareowners, currently scheduled for May 19, 2011.

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	2010 – Present:	Chairman of the Board and Chief Executive Officer of OGE Energy Corp. and OG&E
	2010 – Present:	Chief Executive Officer of Enogex Holdings
	2006 – Present:	Chief Executive Officer of Enogex LLC
	2007 – 2010:	Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp. and OG&E
	2007:	President and Chief Operating Officer of OGE Energy Corp. and OG&E
	2006 – 2007:	Executive Vice President and Chief Operating Officer of OGE Energy Corp. and OG&E
Danny P. Harris	2010 – Present:	President and Chief Operating Officer of OGE Energy Corp. and OG&E, Chief Operating Officer of Enogex Holdings and President of Enogex LLC
	2007 – 2010:	Senior Vice President and Chief Operating Officer of OGE Energy Corp. and OG&E and President of Enogex LLC
	2006 – 2007:	Senior Vice President of OGE Energy Corp. and 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
	2010 – Present:	Chief Financial Officer of Enogex Holdings
	2009 – Present:	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
	2006:	Vice President and Chief Risk Officer of Duke Energy (electric utility)
Patricia D. Horn	2010 – Present:	Vice President – Governance, Environmental, Health & Safety; Corporate Secretary of OGE Energy Corp. and OG&E; Secretary of Enogex Holdings; Vice President –Corporate Secretary of Enogex LLC
	2006 – 2010:	Vice President – Legal, Regulatory and Environmental Health & Safety, General Counsel and Secretary of Enogex LLC
	2006 – 2010:	Assistant General Counsel of OGE Energy Corp.
Gary D. Huneryager	2006 – Present:	Vice President – Internal Audits 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
	2006 – 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
	2006:	Director – Utility Commercial Operations of OG&E
Jean C. Leger, Jr.	2008 – Present:	Vice President – Utility Operations of OG&E
	2006 – 2008:	Vice President of Operations of Enogex LLC
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
	2006 – 2007:	Executive Vice President – Member Services of Teleflora (floral industry and software services to floral industry company)

Name		Business Experience
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)
	2006:	Director of U.S. Operations at Plains All-American Pipeline L.P. (crude oil transportation and storage company)
E. Keith Mitchell	2007 – Present:	Senior Vice President and Chief Operating Officer of Enogex LLC
	2007:	Senior Vice President of Enogex Inc.
	2006 – 2007:	Vice President – Transportation Services of Enogex Inc.
Howard W. Motley	2006 – Present:	Vice President – Regulatory Affairs of OG&E
	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
	2006:	Vice President – Enterprise Architecture of National Oilwell Varco (oil and gas equipment company)
Melvin H. Perkins, Jr.	2007 – Present:	Vice President – Power Delivery of OG&E
	2006 – 2007:	Vice President – Transmission of OG&E
Paul L. Renfrow	2006 – Present:	Vice President – Public Affairs of OGE Energy Corp. and OG&E
William J. Bullard	2010 – Present:	General Counsel of OG&E and Assistant General Counsel of OGE Energy Corp.
	2006 – 2010:	Assistant General Counsel of OGE Energy Corp. and OG&E
Scott Forbes	2006 – 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
Max J. Myers	2009 – Present:	Treasurer of OGE Energy Corp. and OG&E
	2010 – Present:	Treasurer of Enogex Holdings
	2008:	Managing Director of Corporate Development and Finance of OGE Energy Corp. and OG&E
	2006 – 2008:	Manager of Corporate Development of OGE Energy Corp. and OG&E
Jerry A. Peace	2008 – Present:	Chief Risk Officer of OGE Energy Corp. and OG&E
	2006 – 2008:	Chief Risk Officer and Compliance Officer of OGE Energy Corp. and OG&E

ACCESS TO SEC 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 OGE Enogex Holdings and its subsidiaries. In addition to the other information in this 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 conservation, 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& #8217;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 bec ome necessary.

There also is growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation and regulation at the Federal level, actions at the state level, litigation relating to greenhouse gas emissions and pressure for greenhouse gas emission reductions from investor organizations and the international community.

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, offsetting 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 14 of Notes to Consolidated Financial Statements. If legislation or regulations a re passed at the Federal or state levels in the future requiring mandatory reductions of carbon dioxide and other greenhouse gases on 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.

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 OG&E's 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 w ith 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.

Many of our jurisdictions have fuel clauses that permit us to recover 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 a re 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.

OG&E may not realize the expected benefits of its Smart Grid metering system, the Smart Grid metering system may not perform as intended or OG&E may incur costs to deploy the Smart Grid metering system that are not recoverable in rates which could adversely affect our results of operations, consolidated financial position and cash flows.

During 2010, OG&E began implementing its Smart Grid metering infrastructure project for residential and commercial customers. This project, which is expected to be completed by the end of 2012, involves the installation of approximately 792,000 Smart Grid meters throughout OG&E's service territory. Smart Grid meters will allow customer usage data to be transmitted through a communication network to a central collection point, where the data will be stored and used for customer billing and other commercial purposes.

OG&E's total project costs eligible for recovery (those costs expended or accrued by OG&E prior to the termination of the period authorized by the DOE as eligible for grant funds) shall be capped at $366.4 million, inclusive of the DOE grant award amount. The Smart Grid project cost includes the cost of implementing the Norman, Oklahoma smart grid pilot program previously authorized by the OCC. To the extent that OG&E's total expenditure for system-wide deployment of smart grid technology during the eligible period exceeds the Smart Grid project cost, OG&E shall be entitled to offer evidence and seek to establish that the excess above the Smart Grid project cost was prudently incurred and any such contention may be addressed in OG&E's 2013 rate case.

If OG&E does not recognize the expected benefits of its Smart Grid metering system, if OG&E incurs additional Smart Grid metering costs that the OCC does not find reasonable or are unrecoverable or if OG&E cannot integrate the Smart Grid metering system with its customer billing and other computer information systems, this may adversely affect our results of operations, consolidated financial position and cash flows.

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 regional transmission organization and has transferred operational authority (but not ownership) of OG&E's transmission facilities to the SPP regional transmission organization. The SPP regional transmission organization 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 alloca ted 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 regional transmission organization.

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.

Our Investment Agreement with the ArcLight affiliate involves risks and uncertainties.

In November 2010, the ArcLight affiliate acquired an indirect 9.9 percent interest in Enogex LLC and OGE Energy retained a 90.1 percent interest in Enogex LLC. Initially, we are entitled to designate three directors and the ArcLight group is able to designate one director of Enogex Holdings. The Investment Agreement provides the ArcLight group the opportunity to increase its ownership interest by providing equity funding for capital expenditures associated with Enogex's business plan. As its ownership position increases, the ArcLight group will be entitled to increasing board representation. As of February 1, 2011, the ArcLight group has a 13.3 percent membership interest in Enogex Holdings. The ArcLight group will also be entitled, at various ownership thresholds, to certain spec ial board approval rights with respect to certain significant actions taken by Enogex Holdings.

Joint venture arrangements like this involve risks and uncertainties, including the risk of the joint venture partner failing to satisfy its obligations, which may result in certain liabilities to us for commitments; the challenges in achieving strategic objectives and expected benefits of the business arrangement and the risk of conflicts arising between us and our partner and the difficulty of managing and resolving such conflicts.

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 p ipeline 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 15 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 w hat 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 PSI Act, 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 2010, Enogex incurred $26.9 million of capital expenditures and operating costs for pipeline integrity management. Enogex currently estimates that it will incur capital expenditures and operating costs of between $100 million and $150 million from 2011 and 2015 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 thes e 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 even ts 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 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-t erm 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.

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.

OG&E's electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.

OG&E owns and operates coal-fired, natural gas-fired and wind-powered generating facilities. Operation of electric generating facilities involves risks that can adversely affect energy output and efficiency levels. Included among these risks are:

- Increased prices for fuel and fuel transportation as existing contracts expire;
- Facility shutdowns due to a breakdown or failure of equipment or processes or interruptions in fuel supply;
- Operator error or safety related stoppages;
- Disruptions in the delivery of electricity; and
- Catastrophic events such as fires, explosions, floods or other similar occurrences.

Economic conditions could negatively impact our business and our results of operations.

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.

In addition, economic conditions, particularly budget shortfalls, could lead to increased pressure on Federal, state and local governments to raise additional funds, including through increased corporate taxes and/or through delaying, reducing or eliminating tax credits, grants or other incentives, which could have a material adverse impact on our results of operations.

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 type s 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. 60;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 results of operations and cash flows.

Enogex'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, liquefied 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 an d the extent of governmental regulation and taxation.

Enogex's keep-whole natural gas processing arrangements, which constituted 14 percent of its gross margin and accounted for 31 percent of its natural gas processed volumes during 2010, 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 POP and POL natural gas processing agreements constituted eight percent of its gross margin and accounted for 40 percent of its natural gas processed volumes during 2010. 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 POP arrangements and in which it receives proceeds from the sale of NGLs or the NGLs themselves as compen sation for its processing services as POL 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 Enog ex 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 $4.00 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 the se 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, POLs positions and inventories of natural gas.

From time to time, Enogex has instituted a hedging program that was intended to reduce the commodity price risk associated with Enogex's keep-whole and POLs arrangements. At December 31, 2010, Enogex had hedged a portion of its expected NGLs volumes attributable to these arrangements, along with the natural gas MMBtu equivalent for keep-whole volumes, for 2011. 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. 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 Enoge× 7;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 2010, Chesapeake Energy Marketing Inc., Apache Corporation, Devon Energy Production Company L.P., BP America Production Company and Samson Resources Company accounted for 52.5 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 2010, 2009 and 2008, revenues from Enogex's firm intrastate transportation and storage contracts were $116.6 million, $116.8 million and $104.4 million, respectively, of which $47.5 million in each year was attributed to OG&E and $15.3 million in each year was attributed to PSO. Enog ex'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, 2011, the contract will remain in effect at least through April 30, 2012. 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 o f 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 Pension Plan that covers substantially all of our employees hired before December 1, 2009. We also have defined benefit postretirement plans that cover substantially all of our employees hired prior to February 1, 2000. 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, 2010, 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.

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 signifi cant 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, 31 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, 2010, the Company and its subsidiaries had outstanding indebtedness and other liabilities of $5.3 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 c ontractual 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 as well as a Federal regulatory agency which generally possess broad powers to ensure that the needs of the utility customers are being met. To the extent that the state commissions or Federal regulatory agency 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 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.

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 disruptions. 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 could include an increase in the cost of our short-term borrowings, but a reduction in our credit ratings would not result in any defaults or accelerations. Any future downgrade could 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 6,531 MWs at December 31, 2010. 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	2010 Capacity Factor (A)		Unit Capability (MW)	Station Capability (MW)
Muskogee (B)	4	1977	Steam-Turbine	Coal	Base Load	59.8%		505	
	5	1978	Steam-Turbine	Coal	Base Load	66.7%		423	
	6	1984	Steam-Turbine	Coal	Base Load	51.3%		502	1,430
Seminole	1	1971	Steam-Turbine	Gas	Base Load	16.7%		491	
	1GT	1971	Combustion-Turbine	Gas	Peaking	0.2%	(C)	17	
	2	1973	Steam-Turbine	Gas	Base Load	19.5%		494	
	3	1975	Steam-Turbine	Gas/Oil	Base Load	25.0%		502	1,504
Sooner	1	1979	Steam-Turbine	Coal	Base Load	78.2%		522	
	2	1980	Steam-Turbine	Coal	Base Load	50.5%		524	1,046
Horseshoe	6	1958	Steam-Turbine	Gas/Oil	Base Load	19.9%		159	
Lake	7	1963	Combined Cycle	Gas/Oil	Base Load	32.6%		227	
	8	1969	Steam-Turbine	Gas	Base Load	17.5%		380	
	9	2000	Combustion-Turbine	Gas	Peaking	1.6%	(C)	46	
	10	2000	Combustion-Turbine	Gas	Peaking	6.9%	(C)	46	858
Mustang	1	1950	Steam-Turbine	Gas	Peaking	10.0%	(C)	50	
	2	1951	Steam-Turbine	Gas	Peaking	10.0%	(C)	51	
	3	1955	Steam-Turbine	Gas	Base Load	22.4%		113	
	4	1959	Steam-Turbine	Gas	Base Load	17.9%		253	
	5A	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	1.9%	(C)	32	
	5B	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	2.5%	(C)	32	531
Redbud (D)	1	2003	Combined Cycle	Gas	Base Load	44.6%		149	
	2	2003	Combined Cycle	Gas	Base Load	57.3%		147	
	3	2003	Combined Cycle	Gas	Base Load	52.1%		148	
	4	2003	Combined Cycle	Gas	Base Load	56.4%		145	589
McClain (E)	1	2001	Combined Cycle	Gas	Base Load	76.3%		352	352
Woodward	1	1963	Combustion-Turbine	Gas	Peaking	---%	(C)(F)	---	---
Enid	1	1965	Combustion-Turbine	Gas	Peaking	---%	(C)(F)	---	
	2	1965	Combustion-Turbine	Gas	Peaking	---%	(C)(F)	---	
	3	1965	Combustion-Turbine	Gas	Peaking	---%	(C)(F)	---	
	4	1965	Combustion-Turbine	Gas	Peaking	---%	(C)(F)	---	---
Total Generating Capability (all stations, excluding wind stations)									6,310

Station	Year Installed	Location	Number of Units	Fuel Capability	2010 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Centennial	2007	Woodward, OK	80	Wind	32.9%	1.5	120
OU Spirit	2009	Woodward, OK	44	Wind	40.2%	2.3	101
Total Generating Capability (wind stations)							221

(A) 2010 Capacity Factor = 2010 Net Actual Generation / (2010 Net Maximum Capacity (Nameplate Rating in MWs) x Period Hours (8,760 Hours)).
(B) Muskogee Unit 3 was retired in December 2010.
(C) Peaking units are used when additional short-term capacity is required.
(D) Represents OG&E's 51 percent ownership interest in the Redbud Plant.
(E) Represents OG&E's 77 percent ownership interest in the McClain Plant.
(F) This unit did not demonstrate summer capability in 2010 as prescribed by the SPP criteria.

At December 31, 2010, OG&E's transmission system included: (i) 49 substations with a total capacity of 10.3 million kVA and 4,210 structure miles of lines in Oklahoma and (ii) seven substations with a total capacity of 2.5 million kVA and 282 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 346 substations with a total capacity of 8.9 million kVA, 26,394 structure miles of overhead lines, 1,849 miles of underground conduit and 8,759 miles of underground conductors in Oklahoma and (ii) 38 substations with a total capacity of 1.1 million kVA, 2,247 structure miles of overhead lines, 206 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 73102. 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 upo n 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, 2010, Enogex and its subsidiaries owned: (i) 5,903 miles of intrastate natural gas gathering pipelines in Oklahoma and Texas; (ii) 2,285 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 24 Bcf with 650 MMcf/d of maximum withdrawal capacity and 650 MMcf/d of injection capacity; (iv) 576,990 horsepower of owned compression and (v) eight operating natural gas processing plants, with a current total inlet capacity of 823 MMcf/d, and a 50 percent interest in the Atoka natural gas processing plant with an inlet capacity of 20 MMcf/d, 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	2010 Average Daily Inlet Volumes (MMcf/d)	Inlet Capacity (MMcf/d)
Calumet (A)	1969	Lean Oil	Gas/Electric	150	250
Cox City (B) (C)	1994	Cryogenic	Gas/Electric	147	60
Thomas (A)	1981	Cryogenic	Gas	132	135
Clinton (A)	2009	Cryogenic	Electric	120	120
Roger Mills (B)	2008	Refrigeration	Electric	36	100
Canute (B)	1996	Cryogenic	Electric	49	60
Wetumka (A)	1983	Cryogenic	Gas/Electric	41	60
Harrah (A)	1994	Cryogenic	Gas/Electric	14	38
Atoka (D)	2007	Refrigeration	Electric	7	20
Total				696	843

(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) On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. Gas volumes normally processed at the Cox City plant were diverted to other facilities or bypassed around Enogex's system to accommodate production and all of the impacted gathered volumes were back online in December. Enogex plans to install a new 120 MMcf/d train at this facility and expects the facility to return the facility back to full service during the third quarter of 2011.
(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, 2010, the Company's gross property, plant and equipment (excluding construction work in progress) additions were $2.7 billion and gross retirements were $240.3 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 29.1 percent of gross property, plant and equipment (excluding construction work in progress) at December 31, 2010.

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 GAAP, 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 14 and 15 of Notes to Consolidated Financial Statements, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending o r 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. *Hull v. Enogex LLC.* On November 14, 2008, a natural gas gathering pipeline owned by Enogex ruptured in Grady County, near Alex, Oklahoma, resulting in a fire that caused injuries to one resident and destroyed three residential structures. After the incident, Enogex coordinated and assisted the affected residents. Enogex resolved matters with two of the residents and Enogex continued to seek resolution with a remaining resident. This resident filed a legal action in May 2009 in the District Court of Cleveland County, Oklahoma, against OGE Energy and Enogex. This matter was resolved by the parties on April 8, 2010. The ultimate resolution of this incident was not material to the Company in light of previously established reserves and insurance coverage. The Company now considers this case closed.

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 m otion on July 28, 2003. In its 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' amended petition seeks class certification and alleges that 60 defendants, including two of the Company's subsidiary entities, have improperly measured the volume of natural gas. The 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.

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 March 31, 2010, the court denied the plaintiffs' request for rehearing.

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

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 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 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.

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 March 31, 2010, the court denied the plaintiffs' request for rehearing.

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

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, plus attorneys' fees and costs, and punitive damages. 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, 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 o n November 20, 2006 and the court denied Enogex's motion. Enogex companies filed an answer to the amended petition and BP America, Inc. and BP America Production Company'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. *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 had 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 described $2.7 million in take-or-pay damages (including interest) and $36 million in contract repudiation damages (including interest), subject to the limitation described below. In 2001, OG&E agreed to provide the plaintiffs with $5.8 million of consideration and the parties agreed to arbitrate the dispute. On May 19, 2010, the arbitration panel issued an arbitration award in an amount less than the consideration previously paid by OG&E and, as a result, OG&E did not owe any additional amount. The Company now considers this case closed.

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. In January 2007, the Oklahoma Supreme Court "arrested" the District Court action until, and if, the propriety of the complaint of billing practices is determined by the OCC. In September 2008, the plaintiffs filed an application with the OCC asking the OCC to modify its order which authorizes OG&E to collect the challenged franchise fee charges. On December 9, 2009 the OCC issued an order dismissing the plaintiffs' request for a modification of the 1994 OCC order which authorized OG&E to collect and remit sales tax on franchise fee charges. In its December 9, 2009 order, the OCC advised the plaintiffs that the ruling does not address the question of whether OG&E's collection and remittance of such sales tax should be discontinued prospectively. On April 19, 2010, the OCC issued a final order dismissing with prejudice the applicants' claims for recovery of previously paid taxes on franchise fees and approving the closing of this matter. On June 10, 2010, the plaintiffs filed a motion in the District Court of Creek County, Oklahoma, aski ng the court to proceed with the original class action. On July 8, 2010, a hearing in this matter was held and the court granted the plaintiffs motion to lift the stay of discovery previously imposed by the Oklahoma Supreme Court but denied any other specific relief pending further action by the court. On August 4, 2010, OG&E filed an application to assume original jurisdiction and a petition for a writ of prohibition with the Oklahoma Supreme Court. On September 13, 2010, the Oklahoma Supreme Court issued a writ prohibiting the District Court judge from proceeding further in this case except to dismiss the case. On September 20, 2010, the plaintiffs filed a motion to reconsider this matter with the Oklahoma Supreme Court. On December 6, 2010 the Oklahoma Supreme Court denied the plaintiffs motion to reconsider. In compliance with the Oklahoma Su preme Court order, on December 14, 2010, the District Court of Creek County dismissed the lawsuit. OG&E considers this matter closed.

Item 4. [Removed and Reserved]

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	
2011	Paid	High	Low
First Quarter (through January 31)	$ 0.3750	$ 46.60	$ 44.69

	Dividend	Price	
2010	Paid	High	Low
First Quarter	$ 0.3625	$ 39.32	$ 34.92
Second Quarter	0.3625	42.25	33.87
Third Quarter	0.3625	41.11	35.38
Fourth Quarter	0.3625	46.18	39.93

	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

The number of record holders of the Company's Common Stock at December 31, 2010, was 20,942. The book value of the Company's Common Stock at December 31, 2010, was $24.95.

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 p ay dividends on its common stock from dividends paid by OG&E, on OG&E's common stock, and from distributions paid by Enogex Holdings, 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, the covenants of OG&E's certificate of incorporation and its debt instruments limiting the ability of OG&E to pay dividends and the ability of public utility commissions that regulate OG&E to effectively restrict the payment of dividends by OG&E. 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 LLC's debt instruments (including its revolving credit agreement) limitin g the ability of Enogex Holdings 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:

Ÿ 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 common stock, premiums on common stock (restricted to premiums on common stock only by SEC orders), and surplus accounts is less than 20 percent of capitalization;

Ÿ 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

Ÿ 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 currently restricted by these provisions.

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
1/1/10 – 1/31/10	69,300	$ 36.96	N/A	N/A
2/1/10 – 2/28/10	96,500	$ 36.16	N/A	N/A
3/1/10 – 3/31/10	46,300	$ 36.43	N/A	N/A
4/1/10 – 4/30/10	17,100	$ 38.58	N/A	N/A
5/1/10 – 5/31/10	114,100	$ 38.12	N/A	N/A
6/1/10 – 6/30/10	34,400	$ 36.15	N/A	N/A
7/1/10 – 7/31/10	57,300	$ 37.29	N/A	N/A
8/1/10 – 8/31/10	25,200	$ 39.92	N/A	N/A
9/1/10 – 9/30/10	12,900	$ 40.40	N/A	N/A
10/1/10 – 10/31/10	64,800	$ 42.19	N/A	N/A
11/1/10 – 11/30/10	16,900	$ 45.43	N/A	N/A
12/1/10 – 12/31/10	13,000	$ 45.58	N/A	N/A

N/A – not applicable

Item 6. Selected Financial Data.

HISTORICAL DATA

Year ended December 31	**2010**	2009	2008	2007	2006
SELECTED FINANCIAL DATA					
(In millions, except per share data)					
Results of Operations Data:					
Operating revenues	**$ 3,716.9**	$ 2,869.7	$ 4,070.7	$ 3,797.6	$ 4,005.6
Cost of goods sold	**2,187.4**	1,557.7	2,818.0	2,634.7	2,902.5
Gross margin on revenues	**1,529.5**	1,312.0	1,252.7	1,162.9	1,103.1
Operating expenses	**935.6**	820.1	790.6	707.6	670.4
Operating income	**593.9**	491.9	462.1	455.3	432.7
Interest income	**---**	1.4	6.7	2.1	6.2
Allowance for equity funds used during construction	**11.4**	15.1	---	---	4.1
Other income	**13.7**	27.5	15.4	17.4	16.3
Other expense	**17.9**	16.3	25.6	22.7	16.7
Interest expense	**139.7**	137.4	120.0	90.2	96.0
Income tax expense	**161.0**	121.1	101.2	116.7	120.5
Income from continuing operations	**300.4**	261.1	237.4	245.2	226.1
Income from discontinued operations, net of tax	**---**	---	---	---	36.0
Net income	**300.4**	261.1	237.4	245.2	262.1
Less: Net income attributable to noncontrolling interest	**5.1**	2.8	6.0	1.0	---
Net income attributable to OGE Energy	**$ 295.3**	$ 258.3	$ 231.4	$ 244.2	$ 262.1
Basic earnings per average common share attributable to OGE Energy common shareholders					
Income from continuing operations	**$ 3.03**	$ 2.68	$ 2.50	$ 2.66	$ 2.48
Income from discontinued operations, net of tax	**---**	---	---	---	0.40
Net income attributable to OGE Energy common shareholders	**$ 3.03**	$ 2.68	$ 2.50	$ 2.66	$ 2.88
Diluted earnings per average common share attributable to OGE Energy common shareholders					
Income from continuing operations	**$ 2.99**	$ 2.66	$ 2.49	$ 2.64	$ 2.45
Income from discontinued operations, net of tax	**---**	---	---	---	0.39
Net income attributable to OGE Energy common shareholders	**$ 2.99**	$ 2.66	$ 2.49	$ 2.64	$ 2.84
Dividends declared per common share	**$ 1.4625**	$ 1.4275	$ 1.3975	$ 1.3675	$ 1.3375
Balance Sheet Data (at period end):					
Property, plant and equipment, net	**$ 6,464.4**	$ 5,911.6	$ 5,249.8	$ 4,246.3	$ 3,867.5
Total assets	**$ 7,669.1**	$ 7,266.7	$ 6,518.5	$ 5,237.8	$ 4,898.4
Long-term debt	**$ 2,362.9**	$ 2,088.9	$ 2,161.8	$ 1,344.6	$ 1,346.3
Total stockholders' equity	**$ 2,400.0**	$ 2,060.8	$ 1,914.0	$ 1,691.6	$ 1,603.8
CAPITALIZATION RATIOS (A)					
Stockholders' equity	**50.4%**	46.4%	47.0%	55.7%	54.3%
Long-term debt	**49.6%**	53.6%	53.0%	44.3%	45.7%
RATIO OF EARNINGS TO FIXED CHARGES (B)					
Ratio of earnings to fixed charges	**4.02**	3.38	3.55	4.66	4.28

(A) 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)].
(B) 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

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 OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing 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 three business segments: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. Prior to November 1, 2010, OER, whose primary operations are in natural gas marketing, was directly owned by OGE Energy. On November 1, 2010, OGE Energy distributed the equity interests in OER to Enogex LLC. Accordingly, the d iscussion that follows includes the results of OER in Enogex's results for all periods presented. Also, Enogex LLC holds a 50 percent ownership interest in Atoka.

On October 5, 2010, OGE Energy entered into an Investment Agreement with the ArcLight affiliate, pursuant to which the ArcLight affiliate agreed to make an initial equity investment in Enogex Holdings in an amount equal to $183,150,000 in exchange for a 9.9 percent membership interest in Enogex Holdings. As a result of this transaction, ArcLight acquired an indirect 9.9 percent interest in Enogex LLC and OGE Energy retained a 90.1 percent interest in Enogex LLC. The Investment Agreement provides ArcLight the opportunity to increase its ownership interest by providing equity funding for capital expenditures associated with Enogex's business plan. The transaction closed on November 1, 2010. As of February 1, 2011, the ArcLight group has a 13.3 percent membership interest in Enogex Holdin gs. See Note 2 of Notes to Consolidated Financial Statements for a further discussion.

Overview

Company Strategy

The Company's mission is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customers' needs for energy and related services in a safe, reliable and efficient manner. The Company intends to execute its vision by focusing on its regulated electric utility business and unregulated natural gas midstream business. The Company intends to maintain the majority of its assets in the regulated utility business, however, the Company anticipates significant growth opportunities for its natural gas midstream business. The Company's financial objectives include a long-term annual earnings growth rate of five to seven percent on a weather-normalized basis, maintaining a strong credit rating as well as increasing the dividen d to meet the Company's dividend payout objectives. 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 is focused on increased investment to preserve system reliability and meet load growth, leverage its advantageous geographic position to develop renewable energy resources for wind generation 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 and deploy newer technology that improves operational, financial and environmental performance. OG&E also is promoting demand-side management programs to encourage more efficient use of electricity. If these initiatives are successful, OG&E believes it may be able to defer the construction or acquisition of any incremental fossil fuel generation capacity until 2020.

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 NGL 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 dr illing 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's business plan entails growing its businesses and providing attractive financial returns through efficient operations and effective commercial management of its assets, capturing growth opportunities through expansion projects, increased utilization of existing assets and through acquisitions in and around its footprint. Enogex also plans to continue to increase the percentage that fee-based processing agreements represent of the total processing volumes. In addition, Enogex is seeking to geographically diversify its gathering, processing and transportation businesses principally by expanding into other areas that are complementary with the Company's capabilities. Enogex expects to accomplish this diversification by undertaking organic growth projects and through acquisitions.

The Company's corporate strategy is to continue to maintain the diversified asset position of OG&E and Enogex focused on providing competitive energy products and services to customers primarily in the south central United States. The Company will continue to focus on growing products and services with limited or manageable commodity price exposure. The Company believes that many of the risk management activities, commercial skills and market information available from OER provide value in managing Enogex's businesses.

Summary of Operating Results

Prior to November 1, 2010, OER was directly owned by OGE Energy. On November 1, 2010, OGE Energy distributed the equity interests in OER to Enogex LLC. Accordingly, the discussion that follows includes the results of OER in Enogex's results for all periods presented.

2010 compared to 2009. Net income attributable to OGE Energy was $295.3 million, or $2.99 per diluted share, in 2010 as compared to $258.3 million, or $2.66 per diluted share, in 2009. Included in net income attributable to OGE Energy in 2010 was a one-time, non-cash charge of $11.4 million, or $0.11 per diluted share, related to the elimination of the tax deduction for the Medicare Part D subsidy (discussed in Note 8 of Notes to Consolidated Financial Statements). The increase in net income attributable to OGE Energy of $37.0 million, or 14.3 percent, or $0.33 per diluted share, in 2010 as compared to 2009 was primarily due to:

- an increase in net income at OG&E of $15.3 million or 7.6 percent, or $0.12 per diluted share of the Company's common stock, due to a higher gross margin primarily due to rate increases and riders and warmer weather in OG&E's service territory partially offset by higher operation and maintenance expense, higher depreciation and amortization expense and higher income tax expense mainly attributable to higher pre-tax income and the elimination of the tax deduction for the Medicare Part D subsidy (discussed in Note 8 of Notes to Consolidated Financial Statements);
- an increase in net income at Enogex of $29.8 million or 48.6 percent, or $0.29 per diluted share of the Company's common stock, due to a higher gross margin primarily due to higher processing spreads, higher NGLs prices, higher natural gas prices and increased volumes partially offset by higher operation and maintenance expense and higher income tax expense mainly attributable to higher pre-tax income and the elimination of the tax deduction for the Medicare Part D subsidy (discussed in Note 8 of Notes to Consolidated Financial Statements); and

- an increase in the net loss at OGE Energy of $8.1 million, or $0.08 per diluted share of the Company's common stock, due to higher other expense primarily attributable to an increase in charitable contributions to OGE Energy's charitable giving foundation in 2010 and higher income tax expense mainly attributable to the elimination of the tax deduction for the Medicare Part D subsidy (discussed in Note 8 of Notes to Consolidated Financial Statements) partially offset by lower interest expense primarily due to lower average commercial paper borrowings and a lower average interest rate in 2010.

2009 compared to 2008. Net income attributable to OGE Energy was $258.3 million, or $2.66 per diluted share, in 2009 as compared to $231.4 million, or $2.49 per diluted share, in 2008. The increase in net income attributable to OGE Energy of $26.9 million, or 11.6 percent, or $0.17 per diluted share, in 2009 as compared to 2008 was primarily due to:

- an increase in net income at OG&E of $57.4 million or 40.1 percent, or $0.52 per diluted share of the Company's common stock, due to a higher 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 AEFUDC partially offset by higher depreciation and amortization expense, higher interest expense and higher income tax expense;
- a decrease in net income at Enogex of $35.0 million or 36.3 percent, or $0.41 per diluted share of the Company's common stock, 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; and
- a decrease in the net loss at OGE Energy of $4.5 million or 62.5 percent, or $0.06 per diluted share of the Company's common stock, due to lower operation and maintenance expense resulting from lower transaction costs associated with terminated transactions of $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.

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

Recent Developments and Regulatory Matters

Global Climate Change and Environmental Concerns

It is uncertain at this time whether, and in what form, Congress will adopt legislation to restrict greenhouse gas emissions. In the absence of such legislation, the EPA has taken steps to regulate greenhouse gas emissions. Future legislation or rules could require reductions of carbon dioxide and other greenhouse gas emissions from generation facilities. This could result in significant changes to the Company's operations, significant capital expenditures by the Company and a significant increase in the Company's cost of conducting business. The OG&E service territory is in central Oklahoma and borders one of the nation's best wind resource areas. Uncertainty surrounding global climate change and environmental concerns related to new coal-fired generation de velopment 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 and other renewables. The Company believes it can leverage its advantageous geographic position to develop renewable energy resources and transmission to deliver the renewable energy. According to the DOE, Oklahoma ranks ninth among the best states for potential wind generation with 516,822 MWs of potential installed capacity. Per a National Renewable Energy Laboratory map, the majority of Oklahoma's wind resources are located in the western third of the state and on the western edge of OG&E's service territory. Although other U.S. utilities can develop wind farms in this region, OG&E's close proximity to this resource does allow it to focus more on wind generation. 0; In addition, the SPP regional transmission organization has begun to address the relative lack of transmission lines capable of bringing renewable energy out of the wind resource area in western Oklahoma, the Texas panhandle and western Kansas to load centers by planning for more transmission to be built in the area and, due to the proximity of OG&E's service territory and its transmission construction capabilities, OG&E expects to benefit by building a substantial portion of this new transmission network. In addition to significantly increasing overall system reliability, these new transmission resources should provide greater access to additional wind resources that are currently constrained due to existing transmission delivery constraints.

OG&E Smart Grid Project

On July 1, 2010, the OCC approved a settlement with all parties to the OCC consideration of OG&E's application for pre-approval for system-wide deployment of smart grid technology and a recovery rider. The recovery rider was implemented with the first billing cycle in July 2010. For a discussion of the settlement agreement terms related to OG&E's Smart Grid program, see Note 15 of Notes to Consolidated Financial Statements.

OG&E Crossroads Wind Project

In July 2010, the OCC approved a settlement among all the parties to the OCC consideration of OG&E's application for pre-approval of the 197.8 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with Crossroads and a recovery rider. For a discussion of the settlement agreement terms approved by the OCC related to OG&E's Crossroads application, see Note 15 of Notes to Consolidated Financial Statements.

OG&E is in the process of entering into an interconnection agreement with the SPP for Crossroads. As part of the multi-study interconnection process, the SPP conducted an interim operational study to determine the impact Crossroads will have on the existing transmission system. The SPP verbally indicated that limited interconnection would be necessary to address system stability limitations. In order to enable full interconnection of Crossroads, OG&E put forth a mitigation proposal, consisting of a system protection relay system, which has recently received all the necessary SPP working group and committee approvals to be implemented. This will allow Crossroads to interconnect at the anticipated 227.5 MWs. & #160;On December 30, 2010, the SPP posted the results of its interim operational study to reflect the SPP approval of the mitigation strategy. OG&E expects a final interconnection agreement to be put in place by the second quarter of 2011.

OG&E Arkansas OU Spirit Application and Renewable Energy Filing

On January 19, 2011, the APSC issued an order finding that (i) OU Spirit is prudent and is in the public's interest, (ii) the $2.1 million of costs associated with OU Spirit from September 1, 2010 through June 30, 2011 should be recovered through the Energy Cost Recovery rider, which is expected to be filed with the APSC by March 15, 2011 (beginning July 1, 2011, OU Spirit costs are expected to be recovered in base rates resulting from OG&E's 2010 Arkansas rate case) and (iii) the 280 MW wind power purchase agreements are prudent and should be recovered through the Energy Cost Recovery rider.

OG&E 2010 Arkansas Rate Case Filing

On September 28, 2010, OG&E filed a rate case with the APSC requesting a rate increase of $17.7 million, to recover the cost of significant electric system expansions and upgrades, including high-voltage transmission lines and wind energy, that have been completed since the last rate filing in August 2008, as well as rising operating costs. If approved, the targeted implementation date for new electric rates is expected to be during the third quarter of 2011. A hearing in this matter is scheduled for May 24, 2011.

Gathering and Processing System Expansions

Southeastern Oklahoma / East Side Expansions

Enogex has constructed a new compressor station in Coal County, Oklahoma, as well as 10 miles of gathering pipe and related treating facilities. The station is designed to accommodate up to 6,700 horsepower of low pressure compression and is supported by five miles of 20-inch steel pipe and five miles of 12-inch steel pipe. The new compressor station also includes the purchase of associated gas treating facilities for the incremental gas in this area. The initial 5,400 horsepower at the compressor station, and the gathering pipe, are currently in service. The treating facilities were placed into service in January 2011. The capital expenditures for this project were $23 million.

In order to gather additional volume in southeast Oklahoma, Enogex constructed an additional low pressure compressor station in Pittsburg County, Oklahoma. This station includes 5,400 horsepower of compression, together with leased treating facilities. The station was fully operational in December 2010. The capital expenditures associated with this project were $12 million.

Western Oklahoma / Texas Panhandle Expansions

Enogex expanded its gathering infrastructure in the Wheeler County, Texas area with the construction of 16 miles of 10-inch steel pipe, as well as the addition of 5,400 horsepower of compression, which became operational and were placed in service during the third quarter of 2010. The capital expenditures associated with this project were $14 million.

Enogex has constructed 38 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 was constructed in phases, with all segments placed in service in December 2010. The capital expenditures associated with this project were $19 million.

As additional support for the strong production needs surrounding Enogex's Clinton plant, Enogex plans to build six miles of 16-inch high pressure gathering pipe and construct a new compressor station designed to handle 6,700 horsepower of single-stage compression. The initial 4,000 horsepower at the compressor station, and the high pressure gathering pipe, were placed in service in

August 2010, with an additional 1,340 horsepower available for service in December 2010, and another 1,340 horsepower expected to be added during 2011. The capital expenditures for this construction are expected to be $16 million.

Enogex is in the process of constructing a new 200 MMcf/d cryogenic processing plant in Canadian County, Oklahoma. The new plant, which will have inlet and residue compression and will be supported by the installation of 31 miles of 20-inch gathering pipeline, as well as 11 miles of 24-inch transmission pipeline providing takeaway capacity from the plant tailgate, is expected to be in service by November 2011. The capital expenditures associated with this project are expected to be $128 million.

Enogex purchased a 200 MMcf/d natural gas processing plant that will be installed in Wheeler County, Texas. This plant will initially add another 120 MMcf/d of processing capacity to Enogex's system with the ability to increase to its full capacity of 200 MMcf/d with the installation of additional residue compression facilities at a later date. The new plant, which will be supported by the installation of 9,400 horsepower of field compression, is expected to be in service in the second quarter of 2012. The capital expenditures associated with this project are expected to be $125 million.

Enogex is in the process of expanding its gathering infrastructure including the addition of low pressure compression and gathering pipe. The expansion is planned to occur in phases, with the initial phase calling for the installation of 35,000 horsepower of low pressure compression and over 120 miles of gathering pipe across three counties in western Oklahoma. This infrastructure is expected to be completed by the second quarter of 2012. The capital expenditures associated with the initial phase of the expansion are expected to be $167 million.

Transportation System Expansions

In order to accommodate additional deliveries to Bennington, Oklahoma, Enogex added an incremental 17,200 horsepower of gas turbine compression at its Bennington compressor station, as well as other system upgrades. These projects were placed into service in December 2010 and January 2011. The capital expenditures associated with these projects were $27 million.

In August 2010, Enogex completed construction of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Aid in Construction payments of $36.7 million received in excess of construction costs were recognized as Deferred Revenues on the Company's Consolidated Balance Sheet and are being amortized on a straight-line basis of $1.2 million per year over the life of the related FTSA under which service is expected to commence in June 2011.

Cox City Plant Fire

On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. Gas volumes normally processed at the Cox City plant were diverted to other facilities or bypassed around Enogex's system to accommodate production and all of the impacted gathered volumes were back online in December. The 120 MMcf/d train previously slated for installation of a cryogenic processing plant at the Wheeler County, Texas location will now be installed at the existing Cox City plant site to bring the facility back to full capacity. The replacement of the damaged train is expected to return the facility back to full service during the third quarter of 2011. Enoge x is currently developing an estimate of the total costs necessary to return the facility back to full service and anticipates the majority of cost beyond the $10 million deductible will be reimbursed by insurance. As a result of the fire, in December 2010, Enogex recorded a pre-tax loss of $3.5 million representing the net book value of the destroyed components of the fourth train at the Cox City plant. Enogex fully expects to receive insurance proceeds, net of a $10 million deductible to replace the destroyed components, and recorded a $3.5 million pre-tax gain for insurance proceeds as the recovery of the initial loss is considered probable. Enogex will recognize additional insurance recoveries in earnings during 2011 as the insurance claims are resolved.

2011 Outlook

The Company's 2011 earnings guidance is between $299 million and $318 million of net income, or $3.00 to $3.20 per average diluted share.

Key factors and assumptions for 2011 include:

Consolidated OGE Energy

- Approximately 99.5 million average diluted shares outstanding;
- An effective tax rate of 31 percent; and
- A projected loss at the holding company of between $2 million and $4 million, or $0.02 to $0.04 per diluted share, primarily due to interest expense relating to long and short-term debt borrowings.

OG&E

The Company projects OG&E to earn between $209 million and $219 million, or $2.10 to $2.20 per average diluted share, in 2011. The key factors and assumptions include:

- Normal weather patterns are experienced for the year;
- Gross margin of $1.105 billion to $1.115 billion based on sales growth of 0.8 percent on a weather-adjusted basis;
- Operating expenses of $730 million to $740 million, with operation and maintenance expenses comprising 60 percent of the total;
- Interest expense of $115 million to $120 million which assumes the issuance of $300 million of long-term debt in mid-year 2011 and a $10 million reduction to interest expense due to the allowance for borrowed funds used during construction;
- AEFUDC income of $35 million to $40 million; and
- An effective tax rate of 28 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 between $90 million and $104 million, or $0.90 to $1.05 per average diluted share, in 2011 net of the noncontrolling interest. The key factors and assumptions include:

- Total Enogex anticipated gross margin of $435 million to $460 million. The gross margin assumption includes:
  - Transportation and storage gross margin contribution of $145 million to $155 million, of which 80 percent is attributable to the transportation business;
  - Gathering and processing gross margin contribution of $290 million to $305 million, of which 58 percent is attributable to the processing business;
  - Key factors affecting the gathering and processing gross margin forecast are:
    - Assumed increase of five to seven percent in gathered volumes over 2010;
    - Assumed increase of three to five percent in processed volumes over 2010;
    - At the midpoint of Enogex's gathering and processing assumption Enogex has included:
      - Processing contract mix of 41 percent POL, 31 percent keep-whole and 28 percent fixed-fee;
      - Weighted average natural gas price of $4.32 per MMBtu in 2011;
      - Realized weighted average NGLs price of $0.90 per gallon in 2011; and
      - Average price per gallon of condensate of $2.20 in 2011;
- Operating expenses of $235 million to $245 million, with operation and maintenance expenses comprising 65 percent of the total;
- Lost gross margins at the Cox City natural gas processing plant while it is being repaired from the December 2010 fire will be offset by insurance proceeds;
- Interest expense of $20 million to $22 million which assumes an $8 million reduction to interest expense due to capitalized interest;
- An effective tax rate of 38 percent; and
- ArcLight will own approximately 17 percent of Enogex Holdings by the end of 2011.

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, 2010, 2009 and 2008 and the Company's consolidated financial position at December 31, 2010 and 2009. 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)*	**2010**	2009	2008
Operating income	**$ 593.9**	$ 491.9	$ 462.1
Net income attributable to OGE Energy	**$ 295.3**	$ 258.3	$ 231.4
Basic average common shares outstanding	**97.3**	96.2	92.4
Diluted average common shares outstanding	**98.9**	97.2	92.8
Basic earnings per average common share attributable to OGE Energy common shareholders	**$ 3.03**	$ 2.68	$ 2.50
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$ 2.99**	$ 2.66	$ 2.49
Dividends declared per common share	**$ 1.4625**	$ 1.4275	$ 1.3975

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)*	**2010**	2009	2008
OG&E (Electric Utility)	**$ 413.7**	$ 354.1	$ 278.3
Enogex (Natural Gas Midstream Operations)			
Transportation and storage	**72.6**	85.7	67.8
Gathering and processing	**123.9**	60.2	117.4
Marketing (A)	**(15.0)**	(7.5)	6.4
Other Operations (B)	**(1.3)**	(0.6)	(7.8)
Consolidated operating income	**$ 593.9**	$ 491.9	$ 462.1

(A) On November 1, 2010, OGE Energy distributed the equity interests in OER to Enogex LLC. Accordingly, the results of OER are included in Enogex's results for all periods presented.
(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)*	**2010**	2009	2008
Operating revenues	**$ 2,109.9**	$ 1,751.2	$ 1,959.5
Cost of goods sold	**1,000.2**	796.3	1,114.9
Gross margin on revenues	**1,109.7**	954.9	844.6
Other operation and maintenance	**418.1**	348.0	351.6
Depreciation and amortization	**208.7**	187.7	155.0
Taxes other than income	**69.2**	65.1	59.7
Operating income	**413.7**	354.1	278.3
Interest income	**0.1**	1.1	4.4
Allowance for equity funds used during construction	**11.4**	15.1	---
Other income	**6.5**	20.4	3.6
Other expense	**1.6**	6.7	11.8
Interest expense	**103.4**	93.6	79.1
Income tax expense	**111.0**	90.0	52.4
Net income	**$ 215.7**	$ 200.4	$ 143.0
Operating revenues by classification			
Residential	**$ 894.8**	$ 717.9	$ 751.2
Commercial	**521.0**	439.8	479.0
Industrial	**212.5**	172.1	219.8
Oilfield	**162.8**	132.6	151.9
Public authorities and street light	**200.8**	167.7	190.3
Sales for resale	**65.8**	53.6	64.9
Provision for rate refund	**---**	(0.6)	(0.4)
System sales revenues	**2,057.7**	1,683.1	1,856.7
Off-system sales revenues	**21.7**	31.8	68.9
Other	**30.5**	36.3	33.9
Total operating revenues	**$ 2,109.9**	$ 1,751.2	$ 1,959.5
MWH sales by classification (in millions)			
Residential	**9.6**	8.7	9.0
Commercial	**6.7**	6.4	6.5
Industrial	**3.8**	3.6	4.0
Oilfield	**3.1**	2.9	2.9
Public authorities and street light	**3.0**	3.0	3.0
Sales for resale	**1.4**	1.3	1.4
System sales	**27.6**	25.9	26.8
Off-system sales	**0.5**	1.0	1.4
Total sales	**28.1**	26.9	28.2
Number of customers	**782,558**	776,550	770,088
Average cost of energy per KWH - cents			
Natural gas	**4.638**	3.696	8.455
Coal	**1.911**	1.747	1.153
Total fuel	**3.012**	2.474	3.337
Total fuel and purchased power	**3.064**	2.760	3.710
Degree days (A)			
Heating - Actual	**3,528**	3,456	3,394
Heating - Normal	**3,631**	3,631	3,650
Cooling - Actual	**2,328**	1,860	2,081
Cooling - Normal	**1,911**	1,911	1,912

(A) 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.

2010 compared to 2009. OG&E's operating income increased $59.6 million, or 16.8 percent, in 2010 as compared to 2009 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense and higher depreciation and amortization expense as discussed below.

Gross Margin

Gross margin was $1,109.7 million in 2010 as compared to $954.9 million in 2009, an increase of $154.8 million, or 16.2 percent. The gross margin increased primarily due to:

- increased price variance, which included revenues from various rate riders, including the Windspeed rider, the OU Spirit rider, the Oklahoma demand program rider and the Smart Grid rider, and higher revenues from the sales and customer mix, which increased the gross margin by $74.5 million;
- warmer weather in OG&E's service territory resulting in a 25 percent increase in cooling degree days, which increased the gross margin by $46.8 million;
- revenue from the full year effect of the August 2009 Oklahoma rate increase, which increased the gross margin by $24.1 million;
- higher demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by $6.9 million;
- new customer growth in OG&E's service territory, which increased the gross margin by $6.7 million; and
- revenues from the full year effect of the June 2009 Arkansas rate increase, which increased the gross margin by $3.5 million.

These increases in the gross margin were partially offset by lower other revenues due to fewer transmission requests from others on OG&E's system, which decreased the gross margin by $7.7 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $771.0 million in 2010 as compared to $618.5 million in 2009, an increase of $152.5 million, or 24.7 percent, primarily due to higher natural gas prices and increased natural gas generation due to ongoing maintenance at some of OG&E's coal-fired power plants. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for the Company and its customers. In 2010, OG&E's fuel mix was 55 percent coal, 42 percent natural gas and three percent wind. In 2009, OG&E's fuel mix was 60 percent coal, 38 percent natural gas and two percent wind. Purchased p ower costs were $226.5 million in 2010 as compared to $176.6 million in 2009, an increase of $49.9 million, or 28.3 percent, primarily due to an increase in purchases in the energy imbalance service market to meet OG&E's generation load requirements and an increase in short-term power agreements resulting in short-term spot market purchases.

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

Operating Expenses

Other operation and maintenance expenses were $418.1 million in 2010 as compared to $348.0 million in 2009, an increase of $70.1 million, or 20.1 percent. The increase in other operation and maintenance expenses was primarily due to:

- an increase of $16.2 million in contract technical and construction services and an increase of $5.2 million in materials and supplies expense primarily attributable to increased spending for ongoing maintenance at some of OG&E's power plants in 2010 as compared to 2009;
- an increase of $16.2 million in employee benefits expense primarily due to an increase in postretirement benefits due to an increase in medical costs and changes in actuarial assumptions in 2010, a reclassification in May 2009 of 2006 and 2007 pension settlement costs to a regulatory asset, as prescribed in the Arkansas rate case settlement, and an increase in pension expense due to an increase in the amount deferred as a pension regulatory liability in OG&E's Oklahoma jurisdiction resulting from OG&E's 2009 Oklahoma rate case;
- an increase of $9.7 million in allocations from the holding company primarily due to higher contract professional services expense, materials and supplies expense and communication and media services expense;
- an increase of $9.1 million in other marketing and sales expense related to demand-side management initiatives, which expenses are being recovered through a rider;
- an increase of $7.5 million in salaries and wages expense primarily due to salary increases in 2010;

- an increase of $4.8 million due to increased spending on vegetation management related to system hardening, which expenses are being recovered through a rider;
- an increase of $3.4 million in injuries and damages expense primarily due to increased reserves on claims in 2010;
- an increase of $2.1 million in overtime expense due to the storms in January and May 2010; and
- an increase of $1.7 million in temporary labor expense.

These increases in other operation and maintenance expenses were partially offset by a decrease of $3.9 million in incentive compensation expense primarily due to lower accruals in 2010.

Depreciation and amortization expense was $208.7 million in 2010 as compared to $187.7 million in 2009, an increase of $21.0 million, or 11.2 percent, primarily due to additional assets being placed into service, including OU Spirit that was placed into service in November and December 2009 and Windspeed that was placed into service on March 31, 2010.

Additional Information

Allowance for Equity Funds Used During Construction. AEFUDC was $11.4 million in 2010 as compared to $15.1 million in 2009, a decrease of $3.7 million, or 24.5 percent, primarily due to the completion of OU Spirit in November and December 2009 and Windspeed on March 31, 2010.

Other Income. Other income was $6.5 million in 2010 as compared to $20.4 million in 2009, a decrease of $13.9 million, or 68.1 percent. The decrease in other income was primarily due to:

- a decrease of $10.0 million due to a decreased level of gains recognized in the GFB program in 2010 from higher than expected usage resulting from warmer weather in addition to more customers participating in the GFB program in 2010; and
- a decrease of $2.6 million related to the benefit associated with the tax gross-up of AEFUDC.

Other Expense. Other expense was $1.6 million in 2010 as compared to $6.7 million in 2009, a decrease of $5.1 million or 76.1 percent, primarily due to a decrease in charitable contributions in 2010.

Interest Expense. Interest expense was $103.4 million in 2010 as compared to $93.6 million in 2009, an increase of $9.8 million, or 10.5 percent. The increase in interest expense was primarily due to:

- an $8.2 million increase related to the issuance of $250 million of long-term debt in June 2010; and
- a $2.8 million increase due to a lower allowance for borrowed funds used during construction in 2010 as compared to 2009.

Income Tax Expense. Income tax expense was $111.0 million in 2010 as compared to $90.0 million in 2009, an increase of $21.0 million, or 23.3 percent, primarily due to:

- higher pre-tax income in 2010 as compared to 2009;
- an adjustment for the elimination of the tax deduction for the Medicare Part D subsidy (discussed in Note 8 of Notes to Consolidated Financial Statements); and
- the write-off of previously recognized Oklahoma investment tax credits primarily due to expenditures no longer eligible for the Oklahoma investment tax credit related to the change in the tax method of accounting for capitalization of repair expenditures.

These increases in income tax expense were partially offset by an increase in Federal renewable energy credits in 2010 as compared to 2009.

2009 compared to 2008. OG&E’s operating income increased $75.8 million, or 27.2 percent, in 2009 as compared to 2008 primarily due to a higher gross margin partially offset by higher depreciation and amortization expense and higher taxes other than income as discussed below.

Gross Margin

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

- Ÿ increased price variance, which included revenues from various rate riders, including the Redbud Plant 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 $89.5 million;
- Ÿ 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 $28.6 million;
- Ÿ revenues from the Arkansas rate increase, which increased the gross margin by $9.3 million;
- Ÿ new customer growth in OG&E's service territory, which increased the gross margin by $8.1 million; and
- Ÿ 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 $1.8 million.

These increases in the gross margin were partially offset by:

- Ÿ milder weather in OG&E's service territory, which decreased the gross margin by $18.2 million; and
- Ÿ lower demand and related revenues by non-residential customers in OG&E's service territory, which decreased the gross margin by $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 $618.5 million in 2009 as compared to $857.2 million in 2008, a decrease of $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 $176.6 million in 2009 as compared to $257.0 million in 2008, a decrease of $80.4 million, or 31.3 percent, primarily due to the termination of the purchase power agreement with the Redbud Plant following OG&E's purchase of the Redbud Plant in September 2008 as well as a decrease in purchases in the energy imbalance service market.

Operating Expenses

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

- Ÿ a decrease of $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;
- Ÿ a decrease of $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 13 of Notes to Consolidated Financial Statements;
- Ÿ an increase in capitalized labor in 2009 as compared to 2008, which decreased other operation and maintenance expenses by $7.7 million;
- Ÿ a decrease of $3.8 million in fleet transportation expense primarily due to lower fuel costs in 2009; and
- Ÿ a decrease of $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 $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 $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 $5.4 million in pension expense;
- Ÿ an increase of $3.3 million due to OG&E's demand-side management initiatives, which expenses are being recovered through a rider;
- Ÿ an increase of $2.2 million in medical and dental expenses; and
- Ÿ an increase of $2.2 million in materials and supplies expense.

Depreciation and amortization expense was $187.7 million in 2009 as compared to $155.0 million in 2008, an increase of $32.7 million, or 21.1 percent, primarily due to additional assets being placed into service, including the Redbud Plant that was placed into service in September 2008, and amortization of several regulatory assets.

Taxes other than income were $65.1 million in 2009 as compared to $59.7 million in 2008, an increase of $5.4 million, or 9.0 percent, primarily due to higher ad valorem taxes.

Additional Information

Interest Income. Interest income was $1.1 million in 2009 as compared to $4.4 million in 2008, a decrease of $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 $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 Windspeed being constructed by OG&E.

Other Income. Other income was $20.4 million in 2009 as compared to $3.6 million in 2008, an increase of $16.8 million. The increase in other income was primarily due to:

- an increase of $9.7 million related to the benefit associated with the tax gross-up of AEFUDC; and
- an increase of $5.9 million due to an increased level of gains recognized in the GFB program in 2009 from more customers participating in the GFB program in 2009 and lower than expected usage resulting from milder weather in 2009 as compared to 2008.

Other Expense. Other expense was $6.7 million in 2009 as compared to $11.8 million in 2008, a decrease of $5.1 million, or 43.2 percent, primarily due to 2008 write-downs of $7.7 million for deferred costs associated with the cancelled Red Rock power plant and $1.5 million associated with the 2007 and 2006 storm costs partially offset by an increase in charitable contributions of $3.5 million.

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

- an increase of $29.2 million in interest expense related to the issuances of long-term debt in 2008; and
- an increase of $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 $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 $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 $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 $90.0 million in 2009 as compared to $52.4 million in 2008, an increase of $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.

Enogex

Year Ended December 31, 2010	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	**$ 403.6**	**$ 1,005.6**	**$ 798.5**	**$ (500.0)**	**$ 1,707.7**
Cost of goods sold	**246.4**	**733.3**	**804.7**	**(499.3)**	**1,285.1**
Gross margin on revenues	**157.2**	**272.3**	**(6.2)**	**(0.7)**	**422.6**
Other operation and maintenance	**48.9**	**91.5**	**8.4**	**(3.5)**	**145.3**
Depreciation and amortization	**21.8**	**50.5**	**0.1**	**---**	**72.4**
Taxes other than income	**13.9**	**6.4**	**0.3**	**---**	**20.6**
Operating income (loss)	**$ 72.6**	**$ 123.9**	**$ (15.0)**	**$ 2.8**	**$ 184.3**

Year Ended December 31, 2009	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 401.0	$ 657.5	$ 619.9	$ (473.3)	$ 1,205.1
Cost of goods sold	239.9	458.8	617.7	(468.9)	847.5
Gross margin on revenues	161.1	198.7	2.2	(4.4)	357.6
Other operation and maintenance	40.9	87.2	9.2	(4.7)	132.6
Depreciation and amortization	21.3	45.8	0.1	---	67.2
Taxes other than income	13.2	5.5	0.4	---	19.1
Operating income (loss)	$ 85.7	$ 60.2	$ (7.5)	$ 0.3	$ 138.7

Year Ended December 31, 2008	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 625.9	$ 1,053.2	$ 1,529.4	$ (970.0)	$ 2,238.5
Cost of goods sold	479.7	806.4	1,509.5	(965.2)	1,830.4
Gross margin on revenues	146.2	246.8	19.9	(4.8)	408.1
Other operation and maintenance	48.2	87.3	12.9	(5.8)	142.6
Depreciation and amortization	17.5	37.5	0.2	---	55.2
Taxes other than income	12.7	4.6	0.4	---	17.7
Operating income	$ 67.8	$ 117.4	$ 6.4	$ 1.0	$ 192.6

Operating Data

Year Ended December 31	**2010**	2009	2008
Gathered volumes – TBtu/d	**1.32**	1.25	1.16
Incremental transportation volumes – TBtu/d (A)	**0.40**	0.54	0.41
Total throughput volumes – TBtu/d	**1.72**	1.79	1.57
Natural gas processed – TBtu/d	**0.82**	0.70	0.66
NGLs sold (keep-whole) – million gallons	**187**	110	181
NGLs sold (purchased for resale) – million gallons	**470**	351	222
NGLs sold (POLs) – million gallons	**31**	32	23
Total NGLs sold – million gallons	**688**	493	426
Average sales price per gallon	**$ 0.96**	$ 0.77	$ 1.26
Estimated realized keep-whole spreads (B)	**$ 5.74**	$ 4.12	$ 6.15

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

2010 compared to 2009. Enogex's operating income increased $45.6 million, or 32.9 percent, in 2010 as compared to 2009. This increase was primarily due to higher processing spreads, higher NGLs prices, higher natural gas prices, increased volumes and higher GPM of natural gas associated with expansion projects. Additionally, the fourth quarter 2009 addition of the higher efficiency Clinton processing plant enabled Enogex to optimize recoveries across all processing plants. In the normal course of Enogex's business, the operation of its gathering, processing and transportation assets results in the creation of physical natural gas long/short positions. These physical positions can result from gas imbalances, actual versus con tractual settlement differences, fuel tracker obligations and natural gas received in-kind for compensation or reimbursements. Enogex actively manages its monthly net position through either selling excess gas or purchasing additional gas needs from third parties through OER.

Other operation and maintenance expense increased $12.7 million, or 9.6 percent, primarily due to salary increases in 2010, increased costs related to pipeline integrity assessments and other non-capital projects and the 2009 reversal of a reserve related to the dismissal of a previously reported natural gas measurement case partially offset by decreased costs associated with the settlement of the November 2008 pipeline rupture and the recognition of a related insurance reimbursement as discussed in Note 14 of Notes to Consolidated Financial Statements.

Depreciation and amortization expense increased $5.2 million, or 7.7 percent, primarily due to additional assets placed into service in 2009 and 2010.

Taxes other than income increased $1.5 million, or 7.9 percent, primarily due to an increase in ad valorem tax expense as a result of assets placed into service in 2009.

Transportation and Storage

The transportation and storage business contributed $157.2 million of Enogex's consolidated gross margin in 2010 as compared to $161.1 million in 2009, a decrease of $3.9 million, or 2.4 percent. The transportation operations contributed $124.3 million of Enogex's consolidated gross margin in 2010 as compared to $130.3 million in 2009. The storage operations contributed $32.9 million of Enogex's consolidated gross margin in 2010 as compared to $30.8 million in 2009. The transportation and storage gross margin decreased primarily due to:

- lower revenues resulting from refunds associated with lease services under the MEP and Gulf Crossing capacity leases and the firm 311 services due to pipeline integrity work, which decreased the gross margin by $9.2 million;
- lower crosshaul volumes as fewer customers moved natural gas to eastern markets in 2010 as there were smaller differences in natural gas prices at various U.S. market locations partially offset by customers utilizing crosshaul services due to pipeline integrity work on an Enogex pipeline, which decreased the gross margin by $5.7 million;
- lower realized margins on operational storage hedges as the result of lower transacted volumes in 2010 as compared to 2009, which decreased the gross margin by $2.3 million;
- lower storage fees due to a reduction in the market value of storage capacity, which decreased the gross margin by $2.0 million; and
- decreased interruptible transportation revenues due to gathering customers shipping production through the firm capacity leases and firm 311 East side service, which decreased the gross margin by $1.6 million.

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

- lease services under the MEP and Gulf Crossing capacity leases and firm 311 services due to these services being available beginning in the second quarter 2009, which increased the gross margin by $9.0 million;
- no adjustment of natural gas storage inventory in 2010 as compared to $5.8 million lower of cost or market adjustment to the natural gas storage inventory in 2009 due to lower natural gas prices;
- a decrease in the imbalance liability, net of fuel recoveries and natural gas length positions, which increased the gross margin by $1.2 million; and
- higher transportation demand fees due to new contracts which began in 2010, which increased the gross margin by $1.1 million.

Other operation and maintenance expense for the transportation and storage business was $8.0 million, or 19.6 percent, higher in 2010 as compared to 2009 primarily due to salary increases in 2010, increased costs of $3.9 million related to pipeline integrity assessments and other non-capital projects and the 2009 reversal of a $1.5 million reserve related to the dismissal of a previously reported natural gas measurement case.

Gathering and Processing

The gathering and processing business contributed $272.3 million of Enogex's consolidated gross margin in 2010 as compared to $198.7 million in 2009, an increase of $73.6 million, or 37.0 percent. The gathering operations contributed $117.6 million of Enogex's consolidated gross margin in 2010 as compared to $114.0 million in 2009. The processing operations contributed $154.7 million of Enogex's consolidated gross margin in 2010 as compared to $84.7 million in 2009.

In 2010, Enogex realized a higher gross margin in its gathering and processing operations primarily as the result of continued growth in gathered volumes, higher processing spreads, higher NGLs prices and higher natural gas prices, net of Enogex's continued effort to convert customers from keep-whole to fixed-fee processing arrangements. Enogex's processing plants saw a 17.0 percent increase in inlet volumes, an increase in NGLs production as recent expansion projects, primarily in the Granite Wash play and Cana/Woodford Shale play have added richer natural gas to Enogex's system and the fourth quarter 2009 completion of the new higher efficiency Clinton processing plant allowed Enogex to optimize recoveries across all processing plants. In December 2010, a fire occurred at Enogex's Cox City natural gas processing plant, and gas volumes normally processed at the Cox City plant were diverted to other facilities by the end of December. Overall, the above factors resulted in the following:

- increased gross margin on keep-whole processing of $35.8 million;

- Ÿ increased fixed processing fees of $13.8 million; and
- Ÿ increased gross margin on NGLs retained under POL contracts of $11.4 million.

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

- Ÿ an increase in condensate revenues associated with the gathering and processing operations as a result of increased volumes associated with new expansion projects with a higher GPM of natural gas and higher condensate prices, which increased the gross margin by $11.6 million; and
- Ÿ increased gathered volumes associated with expansion projects, which increased the gross margin by $4.3 million.

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

- Ÿ lower volumes and realized margin on sales of physical natural gas long/short positions associated with gathering operations, which decreased the gross margin by $1.3 million, net of imbalance and fuel tracker obligations; and
- Ÿ increased processing fees associated with the increased utilization of a third-party processing plant for processing natural gas associated with Atoka, which decreased the gross margin by $1.2 million.

Other operation and maintenance expense for the gathering and processing business was $4.3 million, or 4.9 percent, higher in 2010 as compared to 2009 primarily due to an increase of $2.1 million in non-capital project costs partially offset by decreased costs associated with the settlement of the November 2008 pipeline rupture and the recognition of a related insurance reimbursement as discussed in Note 14 of Notes to Consolidated Financial Statements.

Marketing

The marketing business recognized a loss of $6.2 million as part of Enogex's consolidated gross margin in 2010 as compared to a gain of $2.2 million in 2009, a decrease of $8.4 million. The marketing gross margin decreased primarily due to:

- Ÿ smaller differences in natural gas prices at various U.S. market locations which resulted in a reduced spread that OER was able to realize from delivering gas under its transportation contracts, which decreased the gross margin by $5.5 million;
- Ÿ timing of the withdrawal and sale of natural gas inventory from OER's storage contracts, which decreased the gross margin by $1.9 million; and
- Ÿ selective deal execution to limit credit and commodity price risks in the current market environment, as well as lack of spreads and volatility in the natural gas commodity markets, resulted in limited opportunities for OER in its customer-focused risk management services and natural gas marketing activities, which decreased the gross margin by $1.0 million.

Enogex Consolidated Information

Interest Expense. Enogex's consolidated interest expense was $30.4 million in 2010 as compared to $36.5 million in 2009, a decrease of $6.1 million, or 16.7 percent, primarily due to:

- Ÿ a decrease of $7.0 million in interest expense in 2010 as compared to 2009 due to a lower interest rate on long-term debt issued in 2009 as compared to the interest rate on long-term debt that was retired in January 2010; and
- Ÿ a $2.8 million tender payment on the tender offer Enogex completed in July 2009 related to the retirement of $110.8 million of senior notes.

These decreases in interest expense were partially offset by a decrease of $3.8 million in capitalized interest related to lower capital expenditures and fewer projects qualifying for capitalized interest in 2010 as compared to 2009.

Income Tax Expense. Enogex's consolidated income tax expense was $57.7 million in 2010 as compared to $37.8 million in 2009, an increase of $19.9 million, or 52.6 percent, primarily due to higher pre-tax income in 2010 as compared to 2009 and an adjustment for the elimination of the tax deduction for the Medicare Part D subsidy (discussed in Note 8 of Notes to Consolidated Financial Statements).

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was $5.1 million in 2010 as compared to $2.8 million in 2009, an increase of $2.3 million, or 82.1 percent, due to the equity investment by the ArcLight group in November 2010 in exchange for a 9.9 percent membership interest in Enogex Holdings.

Non-recurring Items. Enogex had net income of $91.1 million in 2010, which did not include any items that Enogex does not consider to be reflective of its ongoing operations. Enogex had net income of $61.3 million in 2009, which includes a net loss of $0.8 million for items Enogex did not consider to be reflective of its ongoing operations. This decrease in Enogex's consolidated net income included a tender payment on the tender offer Enogex completed in July 2009 of $1.7 million after-tax for the purchase of $110.8 million of Enogex's $400 million 8.125% senior notes that matured on January 15, 2010, which was partially offset by the reversal of a reserve of $0.9 million after-tax in 2009 related to the dismissal of a previously reported natura l gas measurement case.

2009 compared to 2008. Enogex's operating income decreased $53.9 million, or 28.0 percent, in 2009 as compared to 2008. The decrease was 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 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 under the MEP and Gulf Crossing capacity leases and increased capacity due to the addition of the Bennington co mpressor 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 through OER. During 2009, higher volumes and realized margin on physical gas long/short positions increased the gross margin by $9.2 million, net of corresponding imbalance and fuel tracker obligations.

Other operation and maintenance expense decreased $10.0 million, or 7.0 percent, 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 expense increased $12.0 million, or 21.7 percent, primarily due to additional assets placed into service in 2008 and 2009.

Taxes other than income increased $1.4 million, or 7.9 percent, primarily due to an increase in ad valorem tax expense as a result of assets placed into service in 2008.

Transportation and Storage

The transportation and storage business contributed $161.1 million of Enogex's consolidated gross margin in 2009 as compared to $146.2 million in 2008, an increase of $14.9 million, or 10.2 percent. The transportation operations contributed $130.3 million of Enogex's consolidated gross margin in 2009 as compared to $115.8 million in 2008. The storage operations contributed $30.8 million of Enogex's consolidated gross margin in 2009 as compared to $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 $10.3 million;
- implementation of the new Section 311 firm East side service during the second quarter of 2009 that increased transportation fees by $4.2 million;
- completion of the Bennington compressor station which increased take away capacity from Enogex's system and higher demand for crosshaul services as shippers bid up rates to move natural gas on Enogex's system during the first half of the 2009 that increased transportation fees by $3.0 million, net of $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 $2.6 million;
- increased value of storage capacity due to the natural gas price volatility and seasonal spread values that increased storage fees by $1.7 million;
- an 8.6 percent volume increase primarily due to volumes from gathering expansion projects that increased transportation fees by $1.4 million; and
- lower natural gas market prices and reduced injection and withdrawal activity reduced the valuation of the storage field losses by $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 $5.8 million in 2009 as compared to an adjustment of $0.7 million in 2008, which decreased the gross margin by $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 $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 $1.0 million, net of imbalance and fuel tracker obligations.

Other operation and maintenance expense for the transportation and storage business was $7.3 million, or 15.1 percent, lower in 2009 as compared to 2008 primarily due to a $6.6 million reduction in spending for non-capitalized projects in 2009 and lower employee expenses of $1.0 million as the result of cost reduction efforts. Also contributing to the lower operation and maintenance expenses was the 2009 reversal of a reserve of $1.5 million related to the dismissal of a previously reported natural gas measurement case.

Gathering and Processing

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

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

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

- a decrease in condensate revenues by $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 $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 $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 $11.7 million; and
- higher volumes and realized margin on sales of physical natural gas long/short positions associated with gathering operations that increased the gross margin by $10.2 million, net of imbalance and fuel tracker obligations.

Other operation and maintenance expense for the gathering and processing business was $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.

Marketing

The marketing business contributed $2.2 million of Enogex's consolidated gross margin in 2009 as compared to $19.9 million in 2008, a decrease of $17.7 million, or 88.9 percent. The marketing gross margin decreased primarily due to:

- smaller differences in natural gas prices at various U.S. market locations which resulted in a reduced spread that OER was able to realize from delivering gas under its transportation contracts, which decreased the gross margin by $7.2 million;
- the decrease in natural gas prices as well as selective deal execution to limit credit and commodity price risks in the 2009 market environment, resulted in limited opportunities for OER in its customer-focused risk management services and natural gas marketing activities, which decreased the gross margin by $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 by $3.3 million.

Other operation and maintenance expense for the marketing business was $3.7 million, or 28.7 percent, lower in 2009 as compared to 2008, primarily due to:

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

Enogex Consolidated Information

Interest Income. Enogex's consolidated interest income was $0.2 million in 2009 as compared to $3.7 million in 2008, a decrease of $3.5 million, or 94.6 percent, primarily due to lower investment levels and lower interest rates.

Interest Expense. Enogex's consolidated interest expense was $36.5 million in 2009 as compared to $33.0 million in 2008, an increase of $3.5 million, or 10.6 percent, primarily due to:

- an increase in interest expense of $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
- a $2.8 million tender payment on the tender offer Enogex completed in July 2009 related to the retirement of $110.8 million of senior notes.

These increases in interest expense were partially offset by:

- lower interest expense of $3.9 million due to the retirement in July 2009 of $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 $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 $2.0 million due to a decrease in credit support fees.

Income Tax Expense. Enogex's consolidated income tax expense was $37.8 million in 2009 as compared to $60.7 million in 2008, a decrease of $22.9 million, or 37.7 percent, primarily due to lower pre-tax income in 2009 as compared to 2008.

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

Non-recurring Items. Enogex had net income of $61.3 million in 2009, which included a net loss of $0.8 million for items Enogex did not consider to be reflective of its ongoing operations. This decrease in Enogex's consolidated net income included a tender payment on the tender offer Enogex completed in July 2009 of $1.7 million after-tax for the purchase of $110.8 million of Enogex LLC's $400 million 8.125% senior notes that matured on January 15, 2010, which was partially offset by the reversal of a reserve of $0.9 million after-tax in 2009 related to the dismissal of a previously reported natural gas measurement case.

Non-GAAP Financial Measures

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

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

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

Reconciliation of Ongoing Earnings (Loss) to GAAP Net Income (Loss) for the Years Ended 2010, 2009 and 2008

(In millions)	**2010 Ongoing Earnings (Loss)**	**Medicare Part D Tax Subsidy**	**2010 GAAP Net Income (Loss)**	2009 GAAP and Ongoing Net Income (Loss) (A)	2008 GAAP and Ongoing Net Income (Loss) (A)
OG&E	**$ 222.7**	**$ (7.0)**	**$ 215.7**	$ 200.4	$ 143.0
Enogex	**93.1**	**(2.0)**	**91.1**	61.3	96.3
Holding Company	**(9.1)**	**(2.4)**	**(11.5)**	(3.4)	(7.9)
Consolidated	**$ 306.7**	**$(11.4)**	**$ 295.3**	$ 258.3	$ 231.4

(A) There were no one-time charges in 2009 or 2008; therefore, ongoing and GAAP net income are the same.

Reconciliation of Ongoing EPS to GAAP EPS for the Years Ended 2010, 2009 and 2008

(In millions)	**2010 Ongoing EPS**	**Medicare Part D Tax Subsidy**	**2010 GAAP EPS**	2009 GAAP and Ongoing EPS (B)	2008 GAAP and Ongoing EPS (B)
OG&E	**$ 2.25**	**$ (0.07)**	**$ 2.18**	$ 2.06	$ 1.54
Enogex	**0.94**	**(0.02)**	**0.92**	0.63	1.04
Holding Company	**(0.09)**	**(0.02)**	**(0.11)**	(0.03)	(0.09)
Consolidated	**$ 3.10**	**$ (0.11)**	**$ 2.99**	$ 2.66	$ 2.49

(B) There were no one-time charges in 2009 or 2008; therefore, ongoing and GAAP EPS are the same.

Financial Condition

The balance of Cash and Cash Equivalents was $2.3 million and $58.1 million at December 31, 2010 and 2009, respectively, a decrease of $55.8 million, or 96.0 percent. See "Liquidity and Capital Resources – Cash Flows" for a discussion of the changes in Cash and Cash Equivalents.

The balance of Income Taxes Receivable was $4.7 million and $157.7 million at December 31, 2010 and 2009, respectively, a decrease of $153.0 million, or 97.0 percent, primarily due to an income tax refund received in February 2010 related to a carry back of the 2008 tax loss resulting from a change in tax method of accounting for capitalization of repair expenditures.

The balance of Fuel Inventories was $158.8 million and $118.5 million at December 31, 2010 and 2009, respectively, an increase of $40.3 million, or 34.0 percent, primarily due to higher coal balances due to higher volumes and higher average prices at OG&E and a higher natural gas inventory balance at OER due to higher volumes and average prices.

The balance of Deferred Income Taxes asset was $18.7 million and $39.8 million at December 31, 2010 and 2009, respectively, a decrease of $21.1 million, or 53.0 percent, primarily due to a reclassification of the January 1, 2010 balance of Federal tax credits to Deferred Income Taxes liability as a result of the Company expecting to have a net operating loss in 2011 primarily due to the tax effects of bonus depreciation and a reclassification to Premium on Common Stock related to deferred income taxes attributable to contributions by the ArcLight group in November 2010 partially offset by an increase in deferred income taxes from the current year provision accruals.

The balance of Construction Work in Progress was $460.0 million and $335.4 million at December 31, 2010 and 2009, respectively, an increase of $124.6 million, or 37.1 percent, primarily due to increased spending on various distribution, transmission and generation projects, including Crossroads, at OG&E as well as increases from the purchase of compressors and a natural gas processing plant at Enogex partially offset by the costs associated with Windspeed constructed by OG&E which was placed in service on March 31, 2010 being reclassified to Property, Plant and Equipment In Service.

The balance of Short-Term Debt was $145.0 million and $175.0 million at December 31, 2010 and 2009, respectively, a decrease of $30.0 million, or 17.1 percent, primarily due to proceeds received from OG&E's issuance of $250 million in long-term debt in June 2010 and proceeds received from the equity sale of a 9.9 percent membership interest in Enogex Holdings in November 2010, a portion of which were used to repay outstanding commercial paper borrowings partially offset by an increase in commercial paper borrowings in the first quarter of 2010 to repay the remaining balance of Enogex LLC's $400 million 8.125% senior notes which matured on January 15, 2010, dividend and bond interest payments and an increase due to daily operational needs.

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

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

The balance of Fuel Clause Over Recoveries was $29.9 million and $187.5 million at December 31, 2010 and 2009, respectively, a decrease of $157.6 million, or 84.1 percent, primarily due to the fact that the amount billed to retail customers was lower than 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.

The balance of Other Current Liabilities was $55.1 million and $32.4 million at December 31, 2010 and 2009, respectively, an increase of $22.7 million, or 70.1 percent, primarily due to the over recovery of various rate riders, including the Windspeed rider, the OU Spirit rider and the Smart Grid rider, and an increase in legal accruals at OG&E.

The balance of Long-Term Debt was $2,362.9 million and $2,088.9 million at December 31, 2010 and 2009, respectively, an increase of $274.0 million, or 13.1 percent, primarily due to OG&E's issuance of $250 million of long-term debt in June 2010 and borrowings on Enogex LLC's revolving credit agreement.

The balance of Deferred Income Taxes liability was $1,434.8 million and $1,246.6 million at December 31, 2010 and 2009, respectively, an increase of $188.2 million, or 15.1 percent, primarily due to accelerated bonus tax depreciation which resulted in higher Federal and state deferred tax accruals as discussed in Note 8 of Notes to Consolidated Financial Statements.

The balance of Regulatory Liabilities was $193.1 million and $168.2 million at December 31, 2010 and 2009, respectively, an increase of $24.9 million, or 14.8 percent, primarily due to increases related to the removal obligations and Oklahoma pension regulatory liabilities.

The balance of Deferred Revenues was $36.7 million at December 31, 2010 with no balance at December 31, 2009. In August 2010, Enogex completed construction of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Aid in Construction payments of $36.7 million received in excess of construction costs were recognized as Deferred Revenues on the Company's Consolidated Balance Sheet and are being amortized on a straight-line basis of $1.2 million per year over the life of the related FTSA under which service is expected to commence in June 2011.

The balance of Noncontrolling Interest was $110.4 million and $20.0 million at December 31, 2010 and 2009, respectively, an increase of $90.4 million, primarily due to the equity investment in Enogex Holdings by the ArcLight affiliate in November 2010.

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

OG&E has 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. On December 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximu m of $24.0 million.

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

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

Liquidity and Capital Resources

Cash Flows

Year Ended December 31 *(In millions)*	**2010**	2009	2008
Net cash provided from operating activities	**$ 782.5**	$ 654.5	$ 625.0
Net cash used in investing activities	**(846.1)**	(808.5)	(1,184.1)
Net cash provided from financing activities	**7.8**	37.7	724.7

The increase of $128.0 million, or 19.6 percent, in net cash provided from operating activities in 2010 as compared to 2009 was primarily due to:

- an increase in cash receipts for sales at Enogex due to an increase in natural gas prices and NGLs prices and volumes in 2010 as compared to 2009;
- an income tax refund received in February 2010 related to a carry back of the 2008 tax loss resulting from a change in tax method of accounting for capitalization of repair expenditures;
- a cash collateral payment to counterparties of OER related to OER's NGLs hedge positions in 2009; and
- cash received in 2010 from the implementation of rate increases and riders at OG&E.

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

- an increase in payments for purchases at Enogex due to an increase in natural gas prices and NGLs prices and volumes in 2010 as compared to 2009; and
- higher fuel refunds at OG&E in 2010 as compared to 2009.

The increase of $29.5 million, or 4.7 percent, 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 Plant 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 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 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 OER related to OER's existing NGLs hedge positions.

The increase of $37.6 million, or 4.7 percent, in net cash used in investing activities in 2010 as compared to 2009 primarily related to a customer's reimbursement of Enogex's costs related to the ongoing construction of a transportation pipeline in 2009. The decrease of $375.6 million, or 31.7 percent, 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 Plant 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 Windspeed being constructed by OG&E. Partially offsetting the decrease in net cash used in investing activities was a customer's reimbursemen t of Enogex's costs related to the ongoing construction of a transportation pipeline in 2009.

The decrease of $29.9 million, or 79.3 percent, in net cash provided from financing activities in 2010 as compared to 2009 was primarily due to:

- repayment of the remaining balance of Enogex LLC's $400 million 8.125% senior notes which matured on January 15, 2010 partially offset by the retirement of $110.8 million of senior notes related to the tender offer Enogex completed in July 2009;
- proceeds received from the issuance of $450 million of long-term debt at Enogex LLC in June 2009; and
- a decrease in the issuance of common stock in 2010.

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

- proceeds received from the issuance of $250 million of long-term debt at OG&E in June 2010;
- proceeds received from the ArcLight affiliate for the equity investment in Enogex Holdings in November 2010;
- lower repayments of short-term debt borrowings in 2010;
- a higher level of proceeds received from borrowings on Enogex LLC's line of credit in 2010; and
- a higher level of repayments made on Enogex LLC's line of credit in 2009.

The decrease of $687.0 million, or 94.8 percent, 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 LLC's revolving credit agreement in 2009;
- repayments of short-term debt in 2009; and
- the purchase of $110.8 million of Enogex LLC's $400 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 LLC in 2009; and
- an increase in the issuance of common stock in 2009.

Future Capital Requirements and Financing Activities

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, 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.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2011 through 2016 are shown in the following table. 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.

(In millions)	2011	2012	2013	2014	2015	2016
OG&E Base Transmission	$ 50	$ 30	$ 20	$ 20	$ 20	$ 20
OG&E Base Distribution	240	200	200	200	200	200
OG&E Base Generation	95	80	70	70	70	70
OG&E Other	45	30	30	30	30	30
Total OG&E Base Transmission, Distribution, Generation and Other	430	340	320	320	320	320
OG&E Known and Committed Projects:						
Transmission Projects:						
Sunnyside-Hugo (345 kV)	150	20	---	---	---	---
Sooner-Rose Hill (345 kV)	35	15	---	---	---	---
Balanced Portfolio 3E Projects	50	170	140	30	---	---
SPP Priority Projects (A)	10	60	155	90	---	---
Total Transmission Projects	245	265	295	120	---	---
Other Projects:						
Smart Grid Program (B)	70	70	25	30	10	10
Crossroads	250	30	---	---	---	---
System Hardening	20	---	---	---	---	---
Total Other Projects	340	100	25	30	10	10
Total OG&E Known and Committed Projects	585	365	320	150	10	10
Total OG&E (C)	1,015	705	640	470	330	330
Enogex LLC Base Maintenance	80	40	40	40	40	40
Enogex LLC Known and Committed Projects:						
Western Oklahoma / Texas Panhandle Gathering Expansion	275	115	20	90	5	15
Other Gathering Expansion	25	25	20	20	20	20
Total Enogex LLC Known and Committed Projects (D)	380	180	80	150	65	75
OGE Energy	25	25	25	25	25	25
Total capital expenditures	$ 1,420	$ 910	$ 745	$ 645	$ 420	$ 430

(A) On February 4, 2011, OG&E responded to the SPP that OG&E will construct the revised Priority Project as discussed in Note 15 of Notes to Consolidated Financial Statements.
(B) These capital expenditures are net of the Smart Grid $130 million grant approved by the DOE.
(C) The capital expenditures above exclude any environmental expenditures associated with 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 NOX burners and related equipment at the three affected generating stations. Preliminary estimates indicate the cost will be $100 million (plus or minus 30 percent). For further information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations."
(D) These capital expenditures represent 100 percent of Enogex LLC's capital expenditures, of which a portion will be funded by the ArcLight group. In February 2011, OGE Energy and the ArcLight group made contributions of $8.0 million and $71.6 million, respectively, to fund a portion of Enogex LLC's 2011 capital requirements. Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. Specifically, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets and at Enogex, will be evaluated based upon their impact upon achieving the Company's financial objectives. The capital expenditure projections related to Enogex Holdings in the table above reflect base market conditions at February 16, 2011 and do not reflect the potential opportunity for a set of growth projects that could materialize.

Contractual Obligations

The following table summarizes the Company's consolidated contractual obligations at December 31, 2010. See additional information in the Company's Consolidated Statements of Capitalization and Note 14 of Notes to Consolidated Financial Statements.

(In millions)	2011	2012-2013	2014-2015	After 2015	Total
Maturities of long-term debt (A)	$ ---	$ 25.0	$ 300.0	$ 2,045.4	$ 2,370.4
Operating lease obligations					
OG&E railcars	3.2	6.1	5.9	28.8	44.0
Enogex noncancellable operating leases	2.4	1.0	---	---	3.4
Total operating lease obligations	5.6	7.1	5.9	28.8	47.4
Other purchase obligations and commitments					
OG&E cogeneration capacity and fixed operation and maintenance payments	92.5	178.0	168.1	462.1	900.7
OG&E expected cogeneration energy payments	61.9	120.7	144.7	515.7	843.0
OG&E minimum fuel purchase commitments	274.8	274.7	---	---	549.5
OG&E expected wind purchase commitments	41.6	102.5	104.2	793.4	1,041.7
OG&E long-term service agreements	15.7	10.5	33.7	73.3	133.2
OER Cheyenne Plains commitments	5.4	11.9	8.1	---	25.4
OER MEP commitments	2.1	4.2	0.9	---	7.2
OER other commitments	3.0	0.7	---	---	3.7
Total other purchase obligations and commitments	497.0	703.2	459.7	1,844.5	3,504.4
Total contractual obligations	502.6	735.3	765.6	3,918.7	5,922.2
Amounts recoverable through fuel adjustment clause (B)	(381.5)	(504.0)	(254.8)	(1,337.9)	(2,478.2)
Total contractual obligations, net	$ 121.1	$ 231.3	$ 510.8	$ 2,580.8	$ 3,444.0

(A) Maturities of the Company’s long-term debt during the next five years consist of $25.0 million and $300.0 million in years 2013 and 2014, respectively. There are no maturities of the Company’s long-term debt in years 2011, 2012 or 2015.

(B) Includes expected recoveries of costs incurred for OG&E’s railcar operating lease obligations, OG&E’s cogeneration expected energy payments, OG&E’s minimum fuel purchase commitments and OG&E’s expected wind purchase commitments.

OG&E also has 720 MWs of 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 minimum fuel purchase commitments 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.

Pension and Postretirement Benefit Plans

At December 31, 2010, 45.0 percent of the Pension Plan investments were in listed common stocks with the balance primarily invested in bonds, debentures and notes, U.S. Government securities, a commingled fund and a common collective trust as presented in Note 12 of Notes to Consolidated Financial Statements. In 2010, asset returns on the Pension Plan were 12.2 percent due to the continued improvement in the equity market in 2010. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline. During each of 2010 and 2009, the Company made contributions to its Pension Plan of $50 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 2011, the Company may contribute up to $50 million to its Pension Plan. 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.

The following table presents the status of the Company’s Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans at December 31, 2010 and 2009. 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 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		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 *(In millions)*	**2010**	2009	**2010**	2009	**2010**	2009
Benefit obligations	**$ (640.9)**	$ (610.9)	**$ (10.8)**	$ (8.3)	**$ (337.1)**	$ (288.0)
Fair value of plan assets	**574.0**	496.3	**---**	---	**59.3**	55.0
Funded status at end of year	**$ (66.9)**	$ (114.6)	**$ (10.8)**	$ (8.3)	**$ (277.8)**	$ (233.0)

Common Stock Dividends

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 Company's financial objective includes increasing the dividend to meet the Company's dividend payout objectives. 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 2010 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 $0.3750 per share from $0.3625 per share effective with the Company's first quarter 2011 dividend.

Security Ratings

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

Access to reasonably priced capital is dependent in part on credit and security ratings. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrade could include an increase in the cost of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post cash collateral or letters of credit. In the event 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, 2010, the Company would have been required to post $15.7 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2010. In addition, the Company could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

On June 28, 2010, Fitch downgraded OG&E's issuer default rating from A+ to A and OG&E's senior unsecured debt rating from AA- to A+. All other Fitch ratings at OGE Energy and Enogex remained unchanged and with a stable outlook. Fitch indicated that the downgrade at OG&E was primarily due to OG&E's cash flow credit metrics decline over its forecast horizon due to large capital expenditures and the non-cash return for AFUDC. The downgrade did not trigger any collateral requirements or change fees under the revolving credit agreement.

On October 6, 2010, Standard and Poor's revised the outlook on Enogex from stable to negative. All other Standard and Poor's ratings at OGE Energy and OG&E remained unchanged and with a stable outlook. Standard and Poor's indicated that the revised outlook at Enogex was primarily due to the transaction with ArcLight. The revised outlook did not trigger any collateral requirements or change fees under the revolving credit agreement.

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.

2010 Capital Requirements, Sources of Financing and Financing Activities

Total capital requirements, consisting of capital expenditures and maturities of long-term debt, were $1,111.3 million and contractual obligations, net of recoveries through fuel adjustment clauses, were $104.4 million resulting in total net capital requirements and contractual obligations of $1,215.7 million in 2010, of which $27.8 million was to comply with environmental regulations. This compares to net capital requirements of $1,039.8 million and net contractual obligations of $104.2 million totaling $1,144.0 million in 2009, of which $2.1 million was to comply with environmental regulations.

During 2010, 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.

Income Tax Refunds

As discussed in Note 8 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 $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.

As discussed in Note 8 of Notes to Consolidated Financial Statements, the Company had a Federal tax net operating loss for 2009 primarily caused by the accelerated tax depreciation provisions contained within the ARRA. ARRA allowed a current deduction for 50 percent of the cost of certain property placed into service during 2009. This tax loss resulted in a $68 million current income tax receivable related to the 2009 tax year. On November 6, 2009, the Worker, Homeownership, and Business Assistance Act of 2009 was signed into law by the President. This new law provided for a five-year carry back of net operating losses incurred in 2008 or 2009. This expanded carryback period enabled the Company to carry back the entire 2009 tax loss. A carryback claim was filed in March 2010 and a refund of $68 million was received by the Company in April 2010.

Issuance of OG&E Long-Term Debt

On June 8, 2010, OG&E issued $250 million of 5.85% senior notes due June 1, 2040. The proceeds from the issuance were added to the Company's general funds and were used to fund OG&E's ongoing capital expenditure program and for working capital. OG&E expects to issue additional long-term debt from time to time when market conditions are favorable and when the need arises.

Potential Collateral Requirements

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

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

Tax Legislation

As discussed in Note 8 of Notes to Consolidated Financial Statements, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act was signed into law, which included accelerated tax depreciation provisions allowing the Company to record a current income tax deduction for 100 percent of the cost of certain property acquired and placed into service from September 8, 2010 to December 31, 2011. The new law will also allow the Company to record a current income tax deduction for 50 percent of the cost of certain property placed into service from January 1, 2012 to December 31, 2012. For financial accounting purposes, the Company recorded an increase in Non-Current Deferred Income Taxes Liability at December 31, 2010 on the Company's Consolidated Balance Sheet to recognize the financi al statement impact of this new law.

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 and to fund future growth opportunities. Additionally, the Company will have an additional source of funding for growth opportunities at Enogex through the ArcLight group. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $145.0 million and $175.0 million at December 31, 2010 and 2009, respectively. At December 31, 2010, Enogex LLC had $25.0 million in outstanding borrowings under its revolving credit agreement with no outstanding borrowings at December 31, 2009. As Enogex LLC's credit agreement matures on March 31, 2013 along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Consolidated Balance Sheets. At December 31, 2010, the Company had $1,064.7 million of net available liquidity under its revolving credit agreements. 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, 2011 and ending December 31, 2012. At December 31, 2010, the Company had $2.3 million in cash and cash equivalents. See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Expected Issuance of OG&E Long-Term Debt

OG&E expects to issue between $250 million and $300 million of long-term debt in mid-2011, 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 $13 million and $15 million in its DRIP/DSPP in 2011. See Note 9 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

Minimum Quarterly Distributions by Enogex Holdings

As discussed in Note 2 of Notes to Consolidated Financial Statements, pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover the members' respective anticipated tax liabilities plus $12.5 million, to be distributed in proportion to each member's percentage ownership interest. As discussed previously, OGE Holdings has the option to fund between 10 percent and 50 percent of Enogex LLC's capital expenditures which partially or entirely offset the quarterly distributions received.

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 are in the valuation of pension plan assumptions, impairment estimates, contingency reserves, AROs, 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 effec t on the amount of pension expense ultimately recognized. The pension plan rate assumptions are shown in Note 12 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	+/- $28.7 million
Discount rate	+/- 0.25 percent	+/- $17.4 million
Contributions	+ $10 million	+ $10 million

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 no material impairments in 2010, 2009 and 2008.

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 GAAP, 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 Note 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.

Asset Retirement Obligations

The Company has 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 2008, 2009 and 2010, Enogex applied hedge accounting to account for hedges of certain natural gas inventories, contractual long/short positions, natural gas purchases and sales and keep-whole natural gas and NGLs hedges. Maturities of Enogex's cash flow hedging activity at December 31, 2010 occur during 2011. 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 impac t on earnings.

From time to time, OG&E and Enogex may engage in cash flow and fair value hedge transactions to modify the interest rate exposure and not to modify the overall leverage of the debt portfolio.

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 benefit obligations 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, 2010, 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 $0.4 million. At December 31, 2010 and 2009, Accrued Unbilled Revenues were $56.8 million and $57.2 million, respectively. 60;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, 2010, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of $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 $1.6 million and $1.7 million at December 31, 2010 and 2009, respectively.

Natural Gas Transportation and Storage, Gathering and Processing and Marketing Segments

Operating Revenues

Operating revenues for gathering, processing, transportation, storage and marketing 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 A ccounts 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, storage and marketing services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold.

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

Enogex, through OER, 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. OER'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 g ains 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.

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

OER 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. OER'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 positions 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 factor s 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, 2010, unrealized mark-to-market gains were $0.9 million, none of which were calculated utilizing models. At December 31, 2010, 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

Natural gas inventory is held by Enogex, through its transportation and storage business to provide operational support for its pipeline deliveries and through its marketing business to manage its leased storage capacity. In an effort to mitigate market price exposures, Enogex may enter into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is valued using moving average cost and is recorded at the lower of cost or market. Enogex's transportation and storage business maintains natural gas inventory. As part of its recurring marketing activity, OER injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. During 2010, 2009 and 2008, Enogex recorded write-downs to market value related to natural gas storage inventory of $0.3 million, $6.1 million and $6.9 million, respectively. The amount of Enogex's natural gas inventory was $23.9 million and $17.5 million at December 31, 2010 and 2009, 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, gathering and processing and marketing segments was $0.3 million and $0.7 million at December 31, 2010 and 2009, respectively.

Accounting Pronouncement

See Notes to Consolidated Financial Statements for a discussion of an accounting pronouncement that is 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 Note 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 their wastes, requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. 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.

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 is expected to increase the cost of conducting business.

Of the Company's capital expenditures budgeted for 2011 and 2012, $9.1 million and $6.9 million, respectively, are to comply with environmental laws and regulations. The Company's management believes that all of its operations are in substantial compliance with current 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 $35.6 million during 2011 as compared to $27.8 million in 2010. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

Air

Federal Clean Air Act Overview

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 or install emission control equipment. 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.

Hazardous Air Pollutants Emission Standards

On March 15, 2005, the EPA issued the Clean Air Mercury Rule 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 to survey power plant operators about their emissions of mercury and other hazardous air pollutants. The EPA has announced plans to promulgate new hazardous air pollutants emission limitations for coal-fired and oil-fired power plants by November 2011. Any costs associated with future regulation of mercury or other hazardous air pollutants are uncertain at this time.

On March 5, 2009, the EPA initiated rulemaking concerning new hazardous air pollutant emission standards for existing reciprocating internal combustion engines. On March 3, 2010, the EPA published final rules on a portion of its original proposed rule and established hazardous air pollutant emission standards for three types of compression ignition reciprocating internal combustion engines. These amendments were effective May 3, 2010. The remaining provisions of the proposed rule were effective October 19, 2010. The current compliance deadline is three years from their respective effective dates. These regulatory actions are expected to have a significant impact on the Company; however, the precise costs the Company will incur to comply with these remaining proposed regulations, including th e testing and modification of the spark engines, are uncertain at this time.

Regional Haze Control Measures

On June 15, 2005, the EPA issued final amendments to its 1999 regional haze rule. These regulations are intended to protect visibility in certain national parks and wilderness areas throughout the United States. In Oklahoma, the Wichita Mountains are the only area covered under the regulation. However, Oklahoma's impact on parks in other states must also be evaluated. Sulfates and nitrate aerosols can lead to the degradation of visibility.

As required by the Federal regional haze rule, the State of Oklahoma evaluated the installation of BART to reduce emissions that cause or contribute to regional haze from certain sources within the state that were built between 1962 and 1977. Certain of OG&E's units at the Horseshoe Lake, Seminole, Muskogee and Sooner generating stations were evaluated for BART. On February 18, 2010, Oklahoma submitted its SIP to the EPA, which set forth the state's plan for compliance with the Federal regional haze rule. The SIP is subject to the EPA's review and approval. If the EPA does not approve Oklahoma's SIP, the EPA can issue a Federal implementation plan.

The Oklahoma SIP included a waiver from BART requirements for all eligible units at the Horseshoe Lake generating station based on air modeling that showed no significant impact on visibility in nearby national parks and wilderness areas. The SIP also included requirements for reducing emissions of NOX and SO2 from OG&E's seven BART-eligible units at the Seminole, Muskogee and Sooner generating stations. The SIP concluded that BART for reducing NOX emissions at all of the subject units should be the installation of low NOX burners (overfire air and flue gas recirculation was also required on two of the units) and set forth associated NOX emission rates and limits. OG&E preliminarily estimates that the total cost of installing and operating these NOX controls on all covered units, based on recent industry experience and past projects, will be between $70 million and $130 million.

With respect to SO2 emissions, the SIP included an agreement between the Oklahoma Department of Environmental Quality and OG&E that established BART for SO2 control at four coal-fired units located at OG&E's Sooner and Muskogee generating stations as the continued use of low sulfur coal (along with associated emission rates and limits). The SIP specifically rejected the installation and operation of Dry Scrubbers as BART for SO2 control from these units because the state determined that Dry Scrubbers were not cost effective on these units. An alternative obligation was also included in the agreement that would apply in the event that the EPA does not approve Oklahoma's SIP. Under the alternative obligation, OG&E would have two options for reducing SO2 emission rates from subject units. First, OG&E could choose to meet the SO2 emissions limits associated with Dry Scrubbers by January 1, 2018. Second, OG&E could implement a fuel switching alternative whereby OG&E would have 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 the EPA approves Oklahoma's SIP, implementation of the BART requirements set forth in the SIP would be required within five years of approval.

The prospect for the EPA approval of Oklahoma's SIP are uncertain. The EPA is expected to propose its action during the first quarter of 2011. The EPA has indicated that it may issue a Federal implementation plan requiring that OG&E install and operate Dry Scrubbers to control SO2 emissions from the four coal-fired generating units at OG&E's Muskogee and Sooner generating stations. OG&E estimates that installing Dry Scrubbers on these units would cost the Company more than $1.0 billion. The EPA's proposal will be subject to the normal administrative process that includes public notice and comment and the availability of judicial review.

Until the EPA takes final action on the Oklahoma 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.

Acid Rain and Sulfur Dioxide Air Quality Standards

The Federal Clean Air Act includes an acid rain program to reduce SO2 emissions. Reductions were obtained through a program of emission (release) allowances issued by the EPA to power plants covered by the acid rain program. Each allowance permits one ton of SO2 to be released from the chimney. Plants may only release as much SO2 as they have allowances. Allowances may be banked and traded or sold nationwide. Beginning in 2000, OG&E became subject to more stringent SO2 emission requirements in Phase II of the acid rain program. These lower limits had no significant financial impact due to OG&E's earlier decision to burn low sulfur coal. In 2010, OG&E's SO2 emissions were below the allowable limits.

On June 2, 2010, the EPA released its final rule strengthening its NAAQS for SO2. The final rule revokes the existing 24-hour and annual standards and establishes a new lower one-hour standard at a level of 75 parts per billion. The EPA intends to complete attainment designations within two years of promulgation of the revised SO2 standard, which is expected by June 2012. States with areas designated nonattainment in 2012 would need to submit a SIP to the EPA by early 2014 outlining actions that those states will take to meet the EPA's revised standards on or before August 2017. The Company will continue to monitor the EPA's attainment designation activities.

Nitrogen Oxides Air Quality Standards

On January 25, 2010, the EPA released a rule strengthening the NAAQS for oxides of nitrogen as measured by nitrogen dioxide 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 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 2010 were 0.336 lbs/MMBtu.

Particulate Matter Air Quality Standards

On September 21, 2006, the EPA lowered the 24-hour fine particulate NAAQS while retaining the annual NAAQS at its existing 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 Air Quality Standards

Currently, the EPA has designated Oklahoma "in attainment" with the NAAQS for ozone of 0.08 parts per million. In March 2008, the EPA lowered the ambient primary and secondary standards to 0.075 parts per million. Oklahoma had until March 2009 to designate any areas of non-attainment within the state, based on ozone levels in 2006 through 2008. Before the designations were complete, the EPA announced that it 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 and extended the deadline for promulgating initial area designations for the NAAQS to March 12, 2011.

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 EPA has indicated that it expects to issue a final standard by July 2011. In the proposed rule, the EPA set forth an accelerated schedule for implementing a revised ozone NAAQS that could impose compliance deadlines ranging from 2014 to 2031. The Company cannot predict the final outcome of this proposed revision to the ozone NAAQS or its affect on OG&E's or Enogex's operations.

Climate Change and Greenhouse Gas Emissions

Emissions of greenhouse gases, including carbon dioxide, sulfur hexafluoride and methane, may be contributing to warming of the Earth's atmosphere. There are various international agreements that restrict greenhouse gas emissions, but none of them have a binding effect on sources located in the United States. The U.S. Congress has not passed legislation to reduce emissions of greenhouse gases and the future prospects for any such legislation are uncertain. Several states 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. Oklahoma, Arkansas and Texas are not among them.

In the absence of Federal legislation, the EPA is taking steps to regulate greenhouse gas emissions from stationary sources using existing legal authority. 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 reporting requirements apply to 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. For petroleum and natural gas facilities, data collection begins on January 1, 2011, with the first annual report due on March 31, 2012. OG&E already 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, offsetting or sequestering its carbon dioxide emissions.

On June 3, 2010, the EPA issued a final rule that makes certain sources subject to permitting requirements for greenhouse gas emissions. The permitting requirements will become effective in 2011. Significant new sources and existing sources undergoing significant modifications may have to install and operate "best available control technology" to control greenhouse gas emissions. Also, in December 2010, the EPA entered into an agreement to settle litigation brought by states and environmental groups whereby the EPA agreed to issue New Source Performance Standards for greenhouse gas emissions from certain new and modified electric generating units and emissions guidelines for existing units over the next two years. Pursuant to this settlement agreement, the EPA agreed to issue proposed rules by July 2011 and fin al rules by May 2012.

Another impetus for addressing climate change is litigation relating to greenhouse gas emissions and pressure for greenhouse gas emission reductions from investor organizations and the international community. In at least three Federal court cases, nuisance-type claims have been asserted against emitters of carbon dioxide, including several utility companies, alleging that such emissions contribute to global warming. The Supreme Court has agreed to hear one of these cases. Although the Company is not a defendant in any of these proceedings, additional litigation in Federal and state courts over these issues is possible.

OG&E is continuing to evaluate various options for reducing, avoiding, offsetting or sequestering its carbon dioxide emissions. 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, 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 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.

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 NAAQS. Oklahoma submitted a demonstration to the EPA that the state does not affect air quality in downwind states. Air quality modeling conducted by the EPA indicated that the state's demonstration was not sufficient for NOX emissions. On July 6, 2010, the EPA proposed a rule that would require thirty one states and the District of Columbia to reduce power plant emissions that contribute to ozone and fine particulate pollution in neighboring states. Pursuant to this proposed rule, Oklahoma is required to reduce NOX emissions from sources within the state during ozone season (May through September). The EPA is currently considering alternative approaches for achieving the reductions set forth in the proposed rule, including methods on how to allocate emissions allowances. The Company commented on the proposed rule and is monitoring its status. Until final rules are issued, the impact of these proposals on the Company cannot be determined.

Endangered Species

Certain federal laws, including the Bald and Golden Eagle Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which the Company conducts operations, or if additional species in those areas, such as the lesser prairie chicken, become subject to protection, the Company's operations and development projects, particularly transmission projects, wind projects or pipeline operations, could be restricted or delayed, or the Company could be required to implement expensive mit igation measures.

For additional information regarding contingencies relating to environmental laws and regulations, see Note 14 of Notes to Consolidated Financial Statements.

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 interest rates and commodity prices. The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt and commercial paper. The Company is exposed to commodity prices in its operations.

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 market 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. This committee's purpose is to develop and maintain risk policies for Enogex, to provide oversight and guidance for existing and prospective Enogex business activities and to provide governance regarding compliance with Enogex 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 market risk management are being followed. Some of the measures in these policies include VaR limits, position limits, tenor limits and stop loss limits.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable-rate debt and commercial paper. The Company manages its interest rate exposure by monitoring and limiting the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce the effects of these changes. 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 estimates of current rates available for similar issues with similar maturities. 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)*	2011	2012	2013	2014	2015	Thereafter
Fixed-rate debt (A)						
Principal amount	$ ---	$ ---	$ ---	$ 300.0	$ ---	$ 1,910.0
Weighted-average interest rate	---	---	---	6.25 %	---	6.48 %
Variable-rate debt (B)						
Principal amount	---	---	25.0	---	---	$ 135.4
Weighted-average interest rate	---	---	0.57%	---	---	0.49%

(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 incurred by the Company would change interest expense by $1.6 million annually.

Commodity Price Risk

The market risks inherent in the Company’s commodity price 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 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 are conducted throughout the year subject to $2.5 million daily and monthly stop loss limits set by the Risk Oversight Committee. The 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, assuming a 95 percent confidence level. The VaR limit set by the Risk Oversight Committee for the Company’s trading activities is currently $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 commodity price 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. Commodity price risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in quoted market prices. The result of this analysis, which may differ from actual results, reflects net commodity price risk to be $0.1 million at December 31, 2010. This amount represents the Company’s exposure, net of the ArcLight group’s proportional share.

Commodity price risk is present in the Company’s non-trading activities because changes in the prices of natural gas, NGLs and NGLs processing spreads have a direct effect on the compensation the Company receives for operating some of its assets. These prices are subject to fluctuations resulting from changes in supply and demand. 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 operatin g income. Because the commodities covered by these hedges are substantially the same commodities that the Company buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

A sensitivity analysis has been prepared to estimate the Company’s exposure to the commodity price 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. & #160;The result of this analysis, which may differ from actual results, reflects net commodity price risk to be $29.7 million at December 31, 2010. This amount represents the Company’s exposure, net of the ArcLight group’s proportional share.

Item 8. Financial Statements and Supplementary Data.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(In millions, except per share data)*	**2010**	2009	2008
OPERATING REVENUES			
Electric Utility operating revenues	**$ 2,109.9**	$ 1,751.2	$ 1,959.5
Natural Gas Midstream Operations operating revenues	**1,607.0**	1,118.5	2,111.2
Total operating revenues	**3,716.9**	2,869.7	4,070.7
COST OF GOODS SOLD (exclusive of depreciation and amortization shown below)			
Electric Utility cost of goods sold	**952.6**	748.7	1,061.2
Natural Gas Midstream Operations cost of goods sold	**1,234.8**	809.0	1,756.8
Total cost of goods sold	**2,187.4**	1,557.7	2,818.0
Gross margin on revenues	**1,529.5**	1,312.0	1,252.7
OPERATING EXPENSES			
Other operation and maintenance	**549.8**	466.8	492.2
Depreciation and amortization	**292.4**	265.7	217.9
Taxes other than income	**93.4**	87.6	80.5
Total operating expenses	**935.6**	820.1	790.6
OPERATING INCOME	**593.9**	491.9	462.1
OTHER INCOME (EXPENSE)			
Interest income	**---**	1.4	6.7
Allowance for equity funds used during construction	**11.4**	15.1	---
Other income	**13.7**	27.5	15.4
Other expense	**(17.9)**	(16.3)	(25.6)
Net other income (expense)	**7.2**	27.7	(3.5)
INTEREST EXPENSE			
Interest on long-term debt	**139.3**	137.3	103.0
Allowance for borrowed funds used during construction	**(5.5)**	(8.3)	(4.0)
Interest on short-term debt and other interest charges	**5.9**	8.4	21.0
Interest expense	**139.7**	137.4	120.0
INCOME BEFORE TAXES	**461.4**	382.2	338.6
INCOME TAX EXPENSE	**161.0**	121.1	101.2
NET INCOME	**300.4**	261.1	237.4
Less: Net income attributable to noncontrolling interest	**5.1**	2.8	6.0
NET INCOME ATTRIBUTABLE TO OGE ENERGY	**$ 295.3**	$ 258.3	$ 231.4
BASIC AVERAGE COMMON SHARES OUTSTANDING	**97.3**	96.2	92.4
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**98.9**	97.2	92.8
BASIC EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	**$ 3.03**	$ 2.68	$ 2.50
DILUTED EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	**$ 2.99**	$ 2.66	$ 2.49
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.4625**	$ 1.4275	$ 1.3975

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)	**2010**	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 300.4**	$ 261.1	$ 237.4
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation and amortization	**292.4**	265.7	217.9
Deferred income taxes and investment tax credits, net	**146.4**	269.8	123.4
Allowance for equity funds used during construction	**(11.4)**	(15.1)	---
Write-down of regulatory assets	**---**	---	9.2
Stock-based compensation expense	**7.4**	4.1	4.3
Excess tax benefit on stock-based compensation	**(0.7)**	(3.3)	(1.9)
Price risk management assets	**3.9**	27.8	(25.9)
Price risk management liabilities	**8.5**	(88.7)	126.9
Regulatory assets	**24.1**	20.2	13.0
Regulatory liabilities	**(12.4)**	(17.5)	(21.9)
Other assets	**6.3**	(3.5)	(7.8)
Other liabilities	**(37.0)**	(37.7)	(0.8)
Change in certain current assets and liabilities			
Accounts receivable, net	**11.9**	(3.3)	46.3
Accrued unbilled revenues	**0.4**	(10.2)	(1.3)
Income taxes receivable	**153.0**	(157.7)	---
Fuel, materials and supplies inventories	**(45.2)**	(36.1)	(15.2)
Gas imbalance assets	**0.7**	3.0	0.5
Fuel clause under recoveries	**(0.7)**	23.7	3.3
Other current assets	**(5.9)**	(1.4)	(2.2)
Accounts payable	**59.2**	(17.2)	(119.6)
Gas imbalance liabilities	**(5.3)**	(12.9)	13.8
Fuel clause over recoveries	**(157.6)**	178.9	4.4
Other current liabilities	**44.1**	4.8	21.2
Net Cash Provided from Operating Activities	**782.5**	654.5	625.0
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(851.7)**	(847.8)	(1,184.5)
Construction reimbursement	**3.3**	38.8	---
Other investing activities	**2.3**	0.5	0.4
Net Cash Used in Investing Activities	**(846.1)**	(808.5)	(1,184.1)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	**246.2**	444.8	743.0
Contributions from noncontrolling interest partner	**183.2**	---	0.5
Proceeds from line of credit	**115.0**	80.0	145.0
Issuance of common stock	**16.9**	79.6	36.4
Excess tax benefit on stock-based compensation	**0.7**	3.3	1.9
Distributions to noncontrolling interest partner	**(4.0)**	---	---
(Decrease) increase in short-term debt	**(30.0)**	(123.0)	2.2
Repayment of line of credit	**(90.0)**	(200.0)	(25.0)
Dividends paid on common stock	**(141.0)**	(136.2)	(128.2)
Retirement of long-term debt	**(289.2)**	(110.8)	(51.1)
Net Cash Provided from Financing Activities	**7.8**	37.7	724.7
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(55.8)**	(116.3)	165.6
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**58.1**	174.4	8.8
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 2.3**	$ 58.1	$ 174.4

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2010**	2009
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 2.3**	$ 58.1
Accounts receivable, less reserve of $1.9 and $2.4, respectively	**277.9**	291.4
Accrued unbilled revenues	**56.8**	57.2
Income taxes receivable	**4.7**	157.7
Fuel inventories	**158.8**	118.5
Materials and supplies, at average cost	**83.3**	78.4
Price risk management	**1.4**	1.8
Gas imbalances	**2.5**	3.2
Deferred income taxes	**18.7**	39.8
Fuel clause under recoveries	**1.0**	0.3
Other	**24.7**	19.7
Total current assets	**632.1**	826.1
OTHER PROPERTY AND INVESTMENTS, at cost	**44.9**	43.7
PROPERTY, PLANT AND EQUIPMENT		
In service	**9,188.0**	8,617.8
Construction work in progress	**460.0**	335.4
Total property, plant and equipment	**9,648.0**	8,953.2
Less accumulated depreciation	**3,183.6**	3,041.6
Net property, plant and equipment	**6,464.4**	5,911.6
DEFERRED CHARGES AND OTHER ASSETS		
Regulatory assets	**489.4**	448.9
Price risk management	**0.8**	4.3
Other	**37.5**	32.1
Total deferred charges and other assets	**527.7**	485.3
TOTAL ASSETS	**$ 7,669.1**	$ 7,266.7

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2010**	2009
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 145.0**	$ 175.0
Long-term debt due within one year	**---**	289.2
Accounts payable	**321.7**	297.0
Dividends payable	**36.6**	35.1
Customer deposits	**67.0**	85.6
Accrued taxes	**39.3**	37.0
Accrued interest	**53.1**	60.6
Accrued compensation	**43.3**	50.1
Price risk management	**16.8**	14.2
Gas imbalances	**6.7**	12.0
Fuel clause over recoveries	**29.9**	187.5
Other	**55.1**	32.4
Total current liabilities	**814.5**	1,275.7
LONG-TERM DEBT	**2,362.9**	2,088.9
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**372.4**	369.3
Deferred income taxes	**1,434.8**	1,246.6
Deferred investment tax credits	**9.4**	13.1
Regulatory liabilities	**193.1**	168.2
Price risk management	**---**	0.1
Deferred revenues	**36.7**	---
Other	**45.3**	44.0
Total deferred credits and other liabilities	**2,091.7**	1,841.3
Total liabilities	**5,269.1**	5,205.9
COMMITMENTS AND CONTINGENCIES (NOTE 14)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**969.2**	887.7
Retained earnings	**1,380.6**	1,227.8
Accumulated other comprehensive loss, net of tax	**(60.2)**	(74.7)
Total OGE Energy stockholders' equity	**2,289.6**	2,040.8
Noncontrolling interest	**110.4**	20.0
Total stockholders' equity	**2,400.0**	2,060.8
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 7,669.1**	$ 7,266.7

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*		**2010**	2009
STOCKHOLDERS' EQUITY			
Common stock, par value $0.01 per share; authorized 125.0 shares; and outstanding 97.6 and 97.0 shares, respectively		**$ 1.0**	$ 1.0
Premium on common stock		**968.2**	886.7
Retained earnings		**1,380.6**	1,227.8
Accumulated other comprehensive loss, net of tax		**(60.2)**	(74.7)
Total OGE Energy stockholders' equity		**2,289.6**	2,040.8
Noncontrolling interest		**110.4**	20.0
Total stockholders' equity		**2,400.0**	2,060.8
LONG-TERM DEBT			
SERIES	DATE DUE		
Senior Notes - OGE Energy			
5.00%	Senior Notes, Series Due November 15, 2014	**100.0**	100.0
Unamortized discount		**(0.3)**	(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
5.85%	Senior Notes, Series Due June 1, 2040	**250.0**	---
Other Bonds - OG&E			
0.30% - 0.50%	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
0.35% - 0.52%	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
0.33% - 0.55%	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0
Unamortized discount		**(5.0)**	(3.6)
Enogex			
8.125%	Senior Notes, Series Due January 15, 2010	**---**	289.2
0.57%	Enogex LLC Revolving Credit Agreement Due March 31, 2013	**25.0**	---
6.875%	Senior Notes, Series Due July 15, 2014	**200.0**	200.0
6.25%	Senior Notes, Series Due March 15, 2020	**250.0**	250.0
Unamortized discount		**(2.2)**	(2.4)
Total long-term debt		**2,362.9**	2,378.1
Less long-term debt due within one year		**---**	289.2
Total long-term debt (excluding long-term debt due within one year)		**2,362.9**	2,088.9
Total Capitalization		**$ 4,762.9**	$ 4,149.7

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 Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance at December 31, 2007	$ 0.9	$ 755.3	$ 1,005.7	$ (81.0)	$ 10.7	$ 1,691.6
Comprehensive income (loss)						
Net income	---	---	231.4	---	6.0	237.4
Other comprehensive income, net of tax	---	---	---	67.3	---	67.3
Comprehensive income	---	---	231.4	67.3	6.0	304.7
Dividends declared on common stock	---	---	(129.5)	---	---	(129.5)
Contributions from noncontrolling interest partner	---	---	---	---	0.5	0.5
Issuance of common stock	---	36.4	---	---	---	36.4
Stock-based compensation	---	10.3	---	---	---	10.3
Balance at December 31, 2008	$ 0.9	$ 802.0	$ 1,107.6	$ (13.7)	$ 17.2	$ 1,914.0
Comprehensive income (loss)						
Net income	---	---	258.3	---	2.8	261.1
Other comprehensive loss, net of tax	---	---	---	(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	79.5	---	---	---	79.6
Stock-based compensation	---	5.2	---	---	---	5.2
Balance at December 31, 2009	$ 1.0	$ 886.7	$ 1,227.8	$ (74.7)	$ 20.0	$ 2,060.8
Comprehensive income						
Net income	---	---	**295.3**	---	**5.1**	**300.4**
Other comprehensive income, net of tax	---	---	---	**14.5**	**(5.8)**	**8.7**
Comprehensive income (loss)	---	---	**295.3**	**14.5**	**(0.7)**	**309.1**
Dividends declared on common stock	---	---	**(142.5)**	---	---	**(142.5)**
Issuance of common stock	---	**17.0**	---	---	---	**17.0**
Stock-based compensation	---	**10.4**	---	---	---	**10.4**
Contributions from noncontrolling interest partner	---	**88.1**	---	---	**95.1**	**183.2**
Deferred income taxes attributable to contributions from noncontrolling interest partner	---	**(34.0)**	---	---	---	**(34.0)**
Distributions to noncontrolling interest partner	---	---	---	---	**(4.0)**	**(4.0)**
Balance at December 31, 2010	**$ 1.0**	**$ 968.2**	**$ 1,380.6**	**$ (60.2)**	**$ 110.4**	**$ 2,400.0**

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)	**2010**	2009	2008
Net income	**$ 300.4**	$ 261.1	$ 237.4
Other comprehensive income (loss), net of tax			
Defined benefit pension plan and restoration of retirement income plan:			
Amortization of deferred net loss, net of tax of $5.6 million, $2.4 million and ($16.4) million, respectively	**8.9**	3.8	(25.8)
Amortization of prior service cost, net of tax of $0.1 million, ($0.1) million and $0.2 million, respectively	**0.2**	(0.2)	0.3
Defined benefit postretirement plans:			
Amortization of deferred net loss, net of tax of ($1.8) million, ($3.4) million and ($1.0) million, respectively	**(2.9)**	(5.4)	(1.6)
Amortization of deferred net transition obligation, net of tax of $0.1 million, $0.1 million and $0.1 million, respectively	**0.1**	0.1	0.2
Amortization of prior service cost, net of tax of $0.1 million, $0.1 million and $0.1 million, respectively	---	0.2	0.2
Deferred commodity contracts hedging gains (losses), net of tax of $1.4 million, ($37.9) million and $59.5 million, respectively	**2.2**	(59.8)	93.8
Deferred hedging gains on interest rate swaps, net of tax of $0.2 million, $0.2 million and $0.2 million, respectively	**0.2**	0.3	0.2
Other comprehensive income (loss), net of tax	**8.7**	(61.0)	67.3
Total comprehensive income	**309.1**	200.1	304.7
Less: Comprehensive income attributable to noncontrolling interest for sale of equity investment	**(6.2)**	---	---
Less: Comprehensive income attributable to noncontrolling interest	**5.5**	2.8	6.0
Total comprehensive income attributable to OGE Energy	**$ 309.8**	$ 197.3	$ 298.7

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

1. Summary of Significant Accounting Policies

Organization

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 OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing 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 three business segments: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. Prior to November 1, 2010, OER, whose primary operations are in natural gas marketing, was directly owned by OGE Energy. On November 1, 2010, OGE Energy distributed the equity interests in OER to Enogex LLC. Accordingly, the d iscussion that follows includes the results of OER in Enogex's results for all periods presented. Also, Enogex LLC holds a 50 percent ownership interest in Atoka. The Company has consolidated 100 percent of Atoka in its consolidated financial statements as Enogex acts as the managing member of Atoka and has control over the operations of Atoka. Enogex LLC is a Delaware single-member limited liability company.

On October 5, 2010, OGE Energy entered into an Investment Agreement with the ArcLight affiliate, pursuant to which the ArcLight affiliate agreed to make an initial equity investment in Enogex Holdings in an amount equal to $183,150,000 in exchange for a 9.9 percent membership interest in Enogex Holdings. As a result of this transaction, ArcLight acquired an indirect 9.9 percent interest in Enogex LLC and OGE Energy retained a 90.1 percent interest in Enogex LLC. The Investment Agreement provides ArcLight the opportunity to increase its ownership interest by providing equity funding for capital expenditures associated with Enogex's business plan. The transaction closed on November 1, 2010. As of February 1, 2011, the ArcLight group has a 13.3 percent membership interest in Enogex Holdin gs. See Note 2 for a further discussion.

The Company charges operating costs to its subsidiaries based on several factors. Operating costs directly related to specific subsidiaries are assigned to those subsidiaries. Where more than one subsidiary benefits from certain expenditures, the costs are shared between those subsidiaries receiving the benefits. Operating costs incurred for the benefit of all subsidiaries are allocated among the subsidiaries, either as overhead based primarily upon labor costs or using the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. The Company adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. The Compan y 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, 2010 and 2009, the results of its operations and the results of its cash flows for the years ended December 31, 2010, 2009 and 2008, have been included and are of a normal recurring nature except as otherwise disclosed.

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)*		**2010**		2009
Regulatory Assets				
Current				
Fuel clause under recoveries	**$**	**1.0**	$	0.3
Miscellaneous (A)		**4.9**		2.2
Total Current Regulatory Assets	**$**	**5.9**	$	2.5
Non-Current				
Benefit obligations regulatory asset	**$**	**365.5**	$	357.8
Income taxes recoverable from customers, net		**43.3**		19.1
Deferred storm expenses		**28.6**		28.0
Unamortized loss on reacquired debt		**15.3**		16.5
Smart Grid		**14.2**		---
Deferred pension plan expenses		**13.5**		18.1
Red Rock deferred expenses		**7.2**		7.7
Miscellaneous		**1.8**		1.7
Total Non-Current Regulatory Assets	**$**	**489.4**	$	448.9
Regulatory Liabilities				
Current				
Fuel clause over recoveries	**$**	**29.9**	$	187.5
Miscellaneous (B)		**20.9**		7.3
Total Current Regulatory Liabilities	**$**	**50.8**	$	194.8
Non-Current				
Accrued removal obligations, net	**$**	**184.9**	$	168.2
Deferred pension plan expenses		**8.2**		---
Total Non-Current Regulatory Liabilities	**$**	**193.1**	$	168.2

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

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.

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)*		**2010**		2009
Defined benefit pension plan and restoration of retirement income plan:				
Net loss	**$**	**215.0**	$	222.8
Prior service cost		**9.7**		12.5
Defined benefit postretirement plans:				
Net loss		**135.7**		114.9
Net transition obligation		**5.1**		7.6
Total	**$**	**365.5**	$	357.8

The following amounts in the benefit obligations regulatory asset at December 31, 2010 are expected to be recognized as components of net periodic benefit cost in 2011:

(In millions)		
Defined benefit pension plan and restoration of retirement income plan:		
Net loss	**$**	**14.5**
Prior service cost		**2.7**
Defined benefit postretirement plans:		
Net loss		**14.4**
Prior service cost		**(13.7)**
Net transition obligation		**2.5**
Total	**$**	**20.4**

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 in Income Taxes Recoverable from Customers, Net in the regulatory assets and liabilities table above.

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.

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.

In accordance with the OCC order received by OG&E in July 2010 related to its Smart Grid project, OG&E was allowed to establish the following regulatory assets:

- Recovery of the Smart Grid project cost shall be capped at $366.4 million, inclusive of the DOE grant award amount. The Smart Grid project cost includes the cost of system-wide deployment of smart grid technology, including implementing the Norman, Oklahoma smart grid pilot program previously authorized by the OCC. Under the terms of the settlement, the Smart Grid project cost would be deemed to represent an investment that is fair, just and reasonable and in the public interest and to be prudent and will be recognized in OG&E's 2013 general rate case;
- Beginning January 1, 2011, OG&E shall make available the smart grid web portal to all customers having a smart meter. OG&E shall expend funds to educate customers regarding the best use of the information available on the portal. In addition, OG&E shall make available to all customers who do not have internet access the opportunity to receive a monthly home energy report. This report shall be made available, free of charge, to customers eligible for the Company's Low Income Home Energy Assistance Program and/or Senior Citizen program who are without internet service. The incremental costs for web portal access, education and the providing of home energy reports free of charge are to be accumulated as a regulatory asset in an amount up to $6.9 million and recovered in base rates beginning in 2014; and
- The stranded costs associated with OG&E's existing meters which are being replaced by smart meters will be accumulated in a regulatory asset and recovered in base rates beginning in 2014.

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 $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 $3.2 million, which is being amortized over a 10-year period, as allowed in the Arkansas rate order. Both the Oklahoma and Arkansas pension plan expenses ar e reflected in Deferred Pension Plan Expenses asset in the regulatory assets and liabilities table above. Also, in accordance with the OCC order received by OG&E in August 2009 in its Oklahoma rate case, OG&E was allowed to recover a certain amount of pension plan expenses. At December 31, 2010, OG&E had $8.1 million of expenses under this level, which have been recorded as Deferred Pension Plan Expenses liability in the regulatory assets and liabilities table above.

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 th e most significant judgment is exercised are in the valuation of pension plan assumptions, impairment estimates, contingency reserves, AROs, 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.

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 is being recovered through the fuel adjustment clause. The allow ance for uncollectible accounts receivable for Enogex 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 was $1.9 million and $2.4 million at December 31, 2010 and 2009, 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, credit risk is the risk of financial loss to Enogex if counterparties fail to perform their contractual obligations. Enogex maintains 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 $134.9 million and $101.0 million at December 31, 2010 and 2009, respectively.

Enogex

Natural gas inventory is held by Enogex, through its transportation and storage business to provide operational support for its pipeline deliveries and through its marketing business to manage its leased storage capacity. In an effort to mitigate market price exposures, Enogex may enter into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is valued using moving average cost and is recorded at the lower of cost or market. Enogex's transportation and storage business maintains natural gas inventory to provide operational support for its pipeline deliveries. As part of its recurring marketing activity, OER injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. During 2010, 2009 and 20 08, Enogex recorded write-downs to market value related to natural gas storage inventory of $0.3 million, $6.1 million and $6.9 million, respectively. The amount of Enogex's natural gas inventory was $23.9 million and $17.5 million at December 31, 2010 and 2009, 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 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 S tatements of Income as Other Operation and Maintenance Expense.

The table below presents OG&E's ownership interest in the jointly-owned McClain Plant and the jointly-owned Redbud Plant, 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 Plant 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 Plant such as fuel, maintenance expense and other operating expenses are included in the applicable financial statement captions in the Consolidated Statement of Income.

December 31, 2010 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant	**77**	**$ 194.3**	**$ 61.9**	**$ 132.4**
Redbud Plant	**51**	**$ 523.1(A)**	**$ 93.5(B)**	**$ 429.6**

(A) This amount includes a plant acquisition adjustment of $148.3 million.
(B) This amount includes accumulated amortization of the plant acquisition adjustment of $12.6 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.

On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. Gas volumes normally processed at the Cox City plant were diverted to other facilities or bypassed around Enogex's system to accommodate production and all of the impacted gathered volumes were back online in December. As a result of the fire, in December 2010, Enogex recorded a pre-tax loss of $3.5 million representing the net book value of the destroyed components of the fourth train at the Cox City plant. Enogex fully expects to receive insurance proceeds, net of a $10 million deductible, to replace the destroyed components, and recorded a $3.5 million pre-tax gain for i nsurance proceeds as the recovery of the initial loss is considered probable. Enogex will recognize additional insurance recoveries in earnings during 2011 as the insurance claims are resolved. Enogex expects the fourth train to return the facility back to full service during the third quarter of 2011.

OGE Energy Consolidated

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

December 31, 2010 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	**$ 111.1**	**$ 77.5**	**$ 33.6**
OGE Energy property, plant and equipment	**111.1**	**77.5**	**33.6**
OG&E			
Distribution assets	**2,833.4**	**897.4**	**1,936.0**
Electric generation assets	**3,047.1**	**1,164.6**	**1,882.5**
Transmission assets	**1,221.3**	**325.6**	**895.7**
Intangible plant	**26.5**	**20.7**	**5.8**
Other property and equipment	**243.4**	**86.1**	**157.3**
OG&E property, plant and equipment	**7,371.7**	**2,494.4**	**4,877.3**
Enogex			
Transportation and storage assets	**924.7**	**250.0**	**674.7**
Gathering and processing assets	**1,230.8**	**354.6**	**876.2**
Marketing assets	**9.7**	**7.1**	**2.6**
Enogex property, plant and equipment	**2,165.2**	**611.7**	**1,553.5**
Total property, plant and equipment	**$ 9,648.0**	**$ 3,183.6**	**$ 6,464.4**

December 31, 2009 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	$ 107.4	$ 75.8	$ 31.6
OGE Energy property, plant and equipment	107.4	75.8	31.6
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
Marketing assets	7.3	7.0	0.3
Enogex property, plant and equipment	1,962.2	549.8	1,412.4
Total property, plant and equipment	$ 8,953.2	$ 3,041.6	$ 5,911.6

Depreciation and Amortization

OG&E

The provision for depreciation, which was 3.0 percent and 2.9 percent, respectively, of the average depreciable utility plant for 2010 and 2009, 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 2011, the provision for depreciation is projected to be 3.0 percent of the average depreciable utility plant. Amortization of intangibles is computed using the straight-line method. Of the remaining amortizable intangible plant balance at December 31, 2010, 57.3 percent will be amortized over three years with 42.7 percent of the remaining amortizable intangible plant balance at December 31, 2010 b eing 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 $148.3 million for the Redbud Plant, which are being amortized over a 27-year life and $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

For Enogex, depreciation is computed principally on the straight-line method using estimated useful lives of three to 83 years for transportation and storage assets, three to 30 years for gathering and processing assets and three to 10 years for general plant 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

The Company has 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 no material impairments in 2010, 2009 and 2008.

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 8.89 percent, 7.99 percent and 3.58 percent for the years 2010, 2009 and 2008, respectively. The increase in the AFUDC rates in 2010 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 for 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 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' 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 a n 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, storage and marketing 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 A ccounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income. Enogex's key natural gas producer customers in 2010 included Chesapeake Energy Marketing Inc., Apache Corporation, Devon Energy Production Company, L.P., BP America Production Company and Samson Resources Company. During 2010, these five customers accounted for 19.7 percent, 13.1 percent, 11.3 percent, 4.6 percent and 3.8 percent, respectively, of Enogex's gathering and processing volumes. During 2010, Enogex's top 10 natural gas producer customers accounted for 66.6 percent of Enogex's gathering and processing volumes.

Enogex recognizes revenue from natural gas gathering, processing, transportation, storage and marketing services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. Enogex depends on third-party facilities to transport and fractionate NGLs that it delivers to the third party at the tailgates of its processing plants. Additionally, the third party purchases 50 percent of the NGLs delivered to its system, which accounted for $279.8 million (46.0%), $170.0 million (49.5%) and $250.2 million (49.5%), respectively, of Enogex's total NGLs sales in 2010, 2009 and 2008. If this third-party's pipeline or other facilities become partially or fully unavailable, Enogex's revenues and cash flows could be adversely affected.

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

Enogex, through OER, 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. OER'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.

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.

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 and (ii) commodity contracts for the sale of NGLs produced by Enogex's gathering and processing business.

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

December 31 *(In millions)*	**2010**	2009
Defined benefit pension plan and restoration of retirement income plan:		
Net loss	**$ (31.1)**	$ (40.0)
Prior service cost	**(0.5)**	(0.7)
Defined benefit postretirement plans:		
Net loss	**(13.6)**	(10.7)
Net transition obligation	**(0.3)**	(0.4)
Deferred commodity contracts hedging losses	**(19.5)**	(21.7)
Deferred hedging losses on interest rate swaps	**(1.0)**	(1.2)
Total accumulated other comprehensive loss	**(66.0)**	(74.7)
Less: Other comprehensive loss attributable to noncontrolling interest	**(5.8)**	---
Total accumulated other comprehensive loss attributable to OGE Energy	**$ (60.2)**	$ (74.7)

Of the deferred hedging losses at December 31, 2010, $19.5 million are expected to be recognized into earnings during 2011.

Defined Benefit Pension Plan, Restoration of Retirement Income Plan and Postretirement Plans

The amounts in accumulated other comprehensive loss at December 31, 2010 that are expected to be recognized as components of net periodic benefit cost in 2011 are as follows:

(In millions)		
Defined benefit pension plan and restoration of retirement income plan:		
Net loss	**$**	**2.0**
Prior service cost		**0.2**
Defined benefit postretirement plans:		
Net loss		**2.7**
Net transition obligation		**0.2**
Total	**$**	**5.1**

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.&# 160; 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, 2010 and 2009.

Reclassifications

Certain prior year amounts have been reclassified on the Consolidated Statements of Income, Consolidated Balance Sheet and Consolidated Statement of Cash Flows to conform to the 2010 presentation primarily related to the presentation of regulatory assets and liabilities.

2. Investment Agreement with ArcLight

On October 5, 2010, OGE Energy entered into an Investment Agreement with the ArcLight affiliate, pursuant to which the ArcLight affiliate agreed to make an initial equity investment in Enogex Holdings in an amount equal to $183,150,000 in exchange for a 9.9 percent membership interest in Enogex Holdings. This transaction was accounted for as an equity transaction for entities under common control and no gain or loss was recognized in the Company's Consolidated Statement of Income. OGE Energy continues to consolidate 100 percent of Enogex Holdings in its consolidated financial statements as OGE Energy has a controlling financial interest over the operations of Enogex Holdings. The ArcLight group's ownership interest is presented as a noncontrolling interest in the Company's Consolidated Financial Statements .

The transaction closed on November 1, 2010. OGE Energy and the ArcLight affiliate have agreed to indemnify each other for breaches of representations, warranties and covenants contained in the Investment Agreement, and, in the case of OGE Energy, for certain tax matters related to the Company, in each case subject to customary thresholds and survival periods.

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

Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. Specifically, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings. In February 2011, OGE Energy and the ArcLight group made contributions of $8.0 million and $71.6 million, respectively, to fund a portion of Enogex LLC's 2011 capital requirements. Also, on February 1, 2011, OGE Energy sold an additional 0.1 percent membership interest in Enogex Holdings to the ArcLight affiliate for $1.9 million. As a result of these transactions, the ArcLight group has a 13.3 percent membership interest in Enogex Holdings. Until the beginning of 2012, the per unit equity price to be paid will be equal to the initial price that had been paid by ArcLight under the Investment Agreement. On and after January 1, 2012, the equity price per unit will be based on the equity value of Enogex Holdings. Subject to certain adjustments, including for material acquisitions, equity value will be calculated as 9.0 or 9.5 times trailing 12-month EBITDA, depending on the ArcLight group's ownership interest and whether the project has already been identified by Enogex Holdings.

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover the members' respective anticipated tax liabilities plus $12.5 million, to be distributed in proportion to each member's percentage ownership interest. As discussed previously, OGE Holdings has the option to fund between 10 percent and 50 percent of Enogex LLC's capital expenditures which partially or entirely offset the quarterly distributions received.

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

3. Accounting Pronouncement

In January 2010, the Financial Accounting Standards Board issued "Fair Value Measurements and Disclosures: Improving Disclosures about Fair Value Measurements," which required new disclosures and clarified existing disclosure requirements about fair value measurement as set forth in previously issued accounting guidance in this area. The Company adopted the relevant provisions of this new standard effective January 1, 2010 and included the required disclosures beginning in the Company's Form 10-Q for the quarter ended March 31, 2010. The new standard also required additional disclosures related to 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). T hese additional disclosures were effective for interim and annual reporting periods beginning after December 15, 2010. The Company adopted these additional provisions effective January 1, 2011 and will include the required disclosures beginning with the Company's Form 10-Q for the quarter ended March 31, 2011.

4. Fair Value Measurements

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

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and option transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk). Instruments classified as Level 3 include NGLs options.

The Company utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-t erm contracts, forward prices are not as readily available. In these circumstances, NGLs options contracts are valued using internally developed methodologies that consider historical relationships among various commodities that result in management's best estimate of fair value. These contracts are classified as 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 and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Contracts with Master Netting Arrangements

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

The following tables summarize the Company's assets and liabilities that are measured at fair value on a recurring basis at December 31, 2010 and 2009 as well as reconcile the Company's commodity contracts fair value to PRM Assets and Liabilities on the Company's Consolidated Balance Sheets at December 31, 2010 and 2009.

December 31, 2010

(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets	Liabilities (B)
Quoted market prices in active market for identical assets (Level 1)	**$ 20.6**	**$ 20.2**	**$ ---**	**$ ---**
Significant other observable inputs (Level 2)	**2.7**	**30.7**	**2.5**	**2.8**
Significant unobservable inputs (Level 3)	**13.3**	**---**	**---**	**---**
Total fair value	**36.6**	**50.9**	**2.5**	**2.8**
Netting adjustments	**(34.4)**	**(34.1)**	**---**	**---**
Total	**$ 2.2**	**$ 16.8**	**$ 2.5**	**$ 2.8**

December 31, 2009

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

(A) The Company uses the market approach to fair value its gas imbalance assets and liabilities, using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices.
(B) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $3.9 million and $4.0 million at December 31, 2010 and 2009, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

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

	Commodity Contracts			
	Assets		Liabilities	
(In millions)	**2010**	2009	**2010**	2009
Balance at January 1	**$ 49.0**	$ 121.2	**$ 14.7**	$ ---
Total gains or losses				
Included in other comprehensive income	**(10.0)**	(54.0)	**---**	14.7
Settlements	**(25.7)**	(18.2)	**(14.7)**	---
Balance at December 31	**$ 13.3**	$ 49.0	**$ ---**	$ 14.7
Amount of total gains or losses included in earnings attributable to the change in unrealized gains or losses relating to assets and liabilities held at December 31 (reported in Operating Revenues)	**$ ---**	$ ---	**$ ---**	$ ---

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

	2010		2009	
December 31 *(In millions)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Derivative Contracts	**$ 2.2**	**$ 2.2**	$ 6.1	$ 6.1
Price Risk Management Liabilities				
Energy Derivative Contracts	**$ 16.8**	**$ 16.8**	$ 14.3	$ 14.3
Long-Term Debt				
OG&E Senior Notes	**$ 1,655.0**	**$ 1,831.5**	$ 1,406.4	$ 1,492.1
OGE Energy Senior Notes	**99.6**	**106.4**	99.5	102.6
OG&E Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
Enogex LLC Senior Notes	**447.8**	**480.7**	736.8	746.7
Enogex LLC Revolving Credit Agreement	**25.0**	**25.0**	---	---

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 energy derivative contracts was determined generally based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties. The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities.

5. Stock-Based Compensation

In 2008, the Company adopted, and its shareowners approved, the 2008 Stock Incentive Plan. Under the 2008 Stock Incentive 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 Stock Incentive Plan.

The following table summarizes the Company's pre-tax compensation expense and related income tax benefit for the years ended December 31, 2010, 2009 and 2008 related to the Company's performance units and restricted stock.

December 31 *(In millions)*	**2010**	2009	2008
Performance units			
Total shareholder return	**$ 6.8**	$ 4.4	$ 3.2
EPS	**2.5**	1.4	1.2
Total performance units	**9.3**	5.8	4.4
Restricted stock	**0.9**	0.9	0.3
Total compensation expense	**$ 10.2**	$ 6.7	$ 4.7
Income tax benefit	**$ 3.9**	$ 2.7	$ 1.8

During 2010, the Company converted 105,103 performance units based on a payout ratio of 120.69 percent of the target number of performance units granted in February 2007, 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 2010, 2009 and 2008, there were 230,233 shares, 324,651 shares and 875,434 shares, respectively, of new common stock issued pursuant to the Company's stock incentive plans related to exercised stock options and payouts of earned performance units. Cash received from exercised stock options and the income tax benefit realized for the tax deductions from exercised stock options for the years ended December 31, 2010, 2009 and 2008 are shown in the following table.

December 31 *(In millions)*	**2010**	2009	2008
Cash received from stock options exercised	**$ 3.2**	$ 3.5	$ 15.0
Income tax benefit realized for the tax deductions from exercised stock options	**$ 1.0**	$ 0.7	$ 3.3

Performance Units

Under the 2008 Stock Incentive Plan, 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 2008 Stock Incentive Plan). 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 in 2009, 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 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 total shareholder return ranking relative to a peer group of companies. The performance units granted based on 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 t he 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.

Performance Units – Total Shareholder Return

The fair value of the performance units based on total shareholder return 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 total shareholder return. The number of performance units granted based on total shareholder return and the assumptions used to calculate the grant date fair value of the performance units based on total shareholder return are shown in the following table.

	2010	2009	2008
Number of units granted	214,750	316,513	181,892
Expected dividend yield	3.9 %	4.5%	3.8%
Expected price volatility	34.0 %	31.0%	18.7%
Risk-free interest rate	1.42 %	1.25%	2.21%
Expected life of units (in years)	2.87	2.88	2.84
Fair value of units granted	$ 39.43	$ 25.55	$ 33.62

A summary of the activity for the Company's performance units based on total shareholder return at December 31, 2010 and changes during 2010 are shown in the following table. Following the end of the performance period, payout of the performance units based on total shareholder return is determined by the Company's total shareholder return 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 12/31/09	546,467	1:1	
Granted (B)	214,750	1:1	
Converted	(78,997)	1:1	$ 4.1
Forfeited	(12,144)	1:1	
Units Outstanding at 12/31/10	670,076	1:1	$ 40.7
Units Fully Vested at 12/31/10	162,922	1:1	$ 14.8

(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 total shareholder return at December 31, 2010 and changes during 2010 are shown in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/09	467,470	$ 28.27
Granted (C)	214,750	$ 39.43
Vested	(162,922)	$ 33.62
Forfeited	(12,144)	$ 27.99
Units Non-Vested at 12/31/10 (D)	507,154	$ 31.40

(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 507,154 performance units not vested at December 31, 2010, 443,521 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2010, there was $7.0 million in unrecognized compensation cost related to non-vested performance units based on total shareholder return which is expected to be recognized over a weighted-average period of 1.68 years.

Performance Units – 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 un its based on EPS. The number of performance units granted based on EPS and the grant date fair value are shown in the following table.

	2010	2009	2008
Number of units granted	71,585	105,504	60,611
Fair value of units granted	$ 32.44	$ 20.02	$ 29.22

A summary of the activity for the Company's performance units based on EPS at December 31, 2010 and changes during 2010 are shown 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 12/31/09	182,086	1:1	
Granted (B)	71,585	1:1	
Converted	(26,279)	1:1	$ 0.5
Forfeited	(4,047)	1:1	
Units Outstanding at 12/31/10	223,345	1:1	$ 15.9
Units Fully Vested at 12/31/10	54,291	1:1	$ 3.6

(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, 2010 and changes during 2010 are shown in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/09	155,807	$ 23.19
Granted (C)	71,585	$ 32.44
Vested	(54,291)	$ 29.22
Forfeited	(4,047)	$ 22.52
Units Non-Vested at 12/31/10 (D)	169,054	$ 25.26

(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 169,054 performance units not vested at December 31, 2010, 147,841 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2010, there was $1.9 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 1.69 years.

Stock Options

The Company recorded no compensation expense in 2010, 2009 or 2008 as all stock options are fully vested. A summary of the activity for the Company's stock options at December 31, 2010 and changes during 2010 are shown 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 12/31/09	246,744	$ 21.98		
Exercised	(146,400)	$ 21.83	$ 2.5	
Options Outstanding at 12/31/10	100,344	$ 22.19	$ 2.3	2.32 years
Options Fully Vested and Exercisable at 12/31/10	100,344	$ 22.19	$ 2.3	2.32 years

Restricted Stock

Under the 2008 Stock Incentive Plan and in 2008, 2009 and 2010, 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.

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-ve sting restrictions related to the Company's restricted stock. The number of shares of restricted stock granted and forfeited and the grant date fair value are shown in the following table.

	2010	2009	2008
Shares of restricted stock granted	26,653	6,226	56,798
Shares of restricted stock forfeited	1,297	2,915	---
Fair value of restricted stock granted	$ 40.78	$ 33.38	$ 30.84

At December 31, 2010, there was $0.9 million in unrecognized compensation cost related to non-vested restricted stock which is expected to be recognized over a weighted-average period of 2.13 years.

6. Derivative Instruments and Hedging Activities

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

Commodity Price Risk

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

- 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 operations 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 OER'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 OER's marketing and trading activities.

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-rate debt and commercial paper. The Company manages its interest rate exposure by monitoring and limiting the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce the effects of these changes. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Credit Risk

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

Cash Flow Hedges

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

The Company designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing, pipeline and storage operations (operational gas hedges). The Company also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. Maturities of Enogex's cash flow hedging activity at December 31, 2010 occur during 2011.

Fair Value Hedges

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

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

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments are utilized in OER's asset management, marketing and trading activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

At December 31, 2010, the Company had the following derivative instruments that were designated as cash flow hedges.

(In millions)	Gross Notional Volume (A)
	2011
Enogex processing hedges	
NGLs sales	1.3
Natural gas purchases	5.2
Enogex marketing hedges	
Natural gas sales	2.3

(A) Natural gas in MMBtu; NGLs in barrels.

At December 31, 2010, the Company had the following derivative instruments that were not designated as hedging instruments.

(In millions)	Gross Notional Volume (A)	
	Purchases	Sales
Natural gas (B)		
Physical (C)(D)	21.4	51.6
Fixed Swaps/Futures	32.8	31.5
Options	25.0	25.3
Basis Swaps	10.8	7.5

(A) Natural gas in MMBtu; NGLs in barrels.
(B) 89 percent of the natural gas contracts have durations of one year or less, six percent have durations of more than one year and less than two years and five percent have durations of more than two years.
(C) Of the natural gas physical purchases and sales volumes not designated as hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.
(D) Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via Enogex's processing contracts, which are not derivative instruments and are excluded from the table above.

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Company's Consolidated Balance Sheet at December 31, 2010 are as follows:

		Fair Value	
Instrument	**Balance Sheet Location**	**Assets**	**Liabilities**
		(In millions)	
Derivatives Designated as Hedging Instruments			
NGLs			
Financial Options	Current PRM	**$ 13.3**	**$ ---**
Natural Gas			
Financial Futures/Swaps	Current PRM	**---**	**28.8**
	Other Current Assets	**0.6**	**0.3**
Total		**$ 13.9**	**$ 29.1**
Derivatives Not Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Current PRM	**---**	**0.1**
	Other Current Assets	**20.0**	**19.8**
Physical Purchases/Sales	Current PRM	**1.4**	**1.2**
	Non-Current PRM	**0.8**	**---**
Financial Options	Other Current Assets	**0.5**	**0.7**
Total		**$ 22.7**	**$ 21.8**
Total Gross Derivatives (A)		**$ 36.6**	**$ 50.9**

(A) See reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2010 (see Note 4).

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

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

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

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

(C) See reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2009 (see Note 4).

Income Statement Presentation Related to Derivative Instruments

The following table presents the effect of derivative instruments on the Company's Consolidated Statement of Income for the year ended December 31, 2010.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in OCI (A)		Amount Reclassified from Accumulated OCI into Income		Amount Recognized in Income	
NGLs Financial Options	**$**	**(9.7)**	**$**	**1.2**	**$**	**---**
NGLs Financial Futures/Swaps		**1.7**		**(3.7)**		**---**
Natural Gas Financial Futures/Swaps		**(14.9)**		**(25.9)**		**0.2**
Total	**$**	**(22.9)**	**$**	**(28.4)**	**$**	**0.2**

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at December 31, 2010 that is expected to be reclassified into income within the next 12 months is a loss of $29.9 million.

Derivatives Not Designated as Hedging Instruments

(In millions)		**Amount Recognized in Income**
Natural Gas Physical Purchases/Sales	**$**	**(11.7)**
Natural Gas Financial Futures/Swaps		**3.2**
Total	**$**	**(8.5)**

The following table presents the effect of derivative instruments on the Company's Consolidated Statement of Income for the year ended December 31, 2009.

Derivatives in Cash Flow Hedging Relationships

(In millions)		**Amount Recognized in OCI**		**Amount Reclassified from Accumulated OCI into Income**		**Amount Recognized in Income**
NGLs Financial Options	$	(56.4)	$	1.7	$	---
NGLs Financial Futures/Swaps		(33.7)		12.6		---
Natural Gas Financial Futures/Swaps		(19.8)		(26.5)		(0.2)
Total	$	(109.9)	$	(12.2)	$	(0.2)

Derivatives Not Designated as Hedging Instruments

(In millions)		**Amount Recognized in Income**
Natural Gas Physical Purchases/Sales	$	(24.3)
Natural Gas Financial Futures/Swaps		17.7
NGLs Financial Futures/Swaps		(0.2)
Total	$	(6.8)

For derivatives designated as cash flow hedges in the tables above, amounts reclassified from Accumulated Other Comprehensive Income into income (effective portion) and amounts recognized in income (ineffective portion) for the years ended December 31, 2010 and 2009, if any, are reported in Operating Revenues. For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2010 and 2009, if any, are reported in Operating Revenues.

Credit-Risk Related Contingent Features in Derivative Instruments

In the event 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, 2010, the Company would have been required to post $15.7 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2010. In addition, the Company could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

7. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affected recognized assets and liabilities but which did 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)*	**2010**	2009	2008
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Power plant long-term service agreement	**$ 2.7**	$ ---	$ 3.5
Future installment payments to wind farm developer	**2.3**	3.9	---
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $8.1, $14.7, $7.6)	**$ 144.6**	$ 125.8	$ 122.3
Income taxes (net of income tax refunds)	**(139.5)**	2.0	---

8. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2010**	2009	2008
Provision (Benefit) for Current Income Taxes			
Federal	**$ 15.8**	$ (145.3)	$ (18.2)
State	**2.3**	(4.8)	(1.2)
Total Provision (Benefit) for Current Income Taxes	**18.1**	(150.1)	(19.4)
Provision for Deferred Income Taxes, net			
Federal	**134.5**	256.7	126.2
State	**9.3**	8.1	1.9
Total Provision for Deferred Income Taxes, net	**143.8**	264.8	128.1
Deferred Federal Investment Tax Credits, net	**(3.7)**	(4.2)	(4.6)
Income Taxes Relating to Other Income and Deductions	**2.8**	10.6	(2.9)
Total Income Tax Expense	**$ 161.0**	$ 121.1	$ 101.2

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 2007 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. OG&E earns both Federal and Oklahoma state tax credits associated with the production from its wind farms. In addition, OG&E and Enogex earn Oklahoma state tax credits associated with their investments in electric generating and natural gas processing facilities which further reduce the Company’s effective tax rate. The following schedule reconciles the statutory Federal tax rate to the effective income tax rate:

Year ended December 31	**2010**	2009	2008
Statutory Federal tax rate	**35.0%**	35.0%	35.0%
Medicare Part D subsidy	**2.6**	(1.1)	(0.3)
State income taxes, net of Federal income tax benefit	**1.7**	1.0	0.2
Amortization of net unfunded deferred taxes	**0.7**	0.7	0.7
Qualified production activities	**(0.2)**	---	---
Income attributable to noncontrolling interest	**(0.4)**	---	---
401(k) dividends	**(0.6)**	(0.7)	(0.8)
Federal investment tax credits, net	**(0.8)**	(1.1)	(1.4)
Federal renewable energy credit (A)	**(3.4)**	(2.2)	(2.7)
Other	**0.3**	0.1	(0.8)
Effective income tax rate	**34.9%**	31.7%	29.9%

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

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. The accounting method change was for income tax purposes only and would allow the Company to record a cumulative tax deduction. For financial accounting purposes, the only change was 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 $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 Dec ember 31, 2009.

At December 31, 2010 and 2009, 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 Deferred Income Taxes at December 31, 2010 and 2009, respectively, were as follows:

December 31 *(In millions)*	**2010**	2009
Current Deferred Income Tax Assets		
Accrued liabilities	**$ 8.2**	$ 4.7
Accrued vacation	**6.1**	7.0
Derivative instruments	**1.0**	8.9
Uncollectible accounts	**0.6**	0.9
Federal tax credits	**---**	17.3
Other	**2.8**	2.6
Total Current Deferred Income Tax Assets	**18.7**	41.4
Current Accrued Income Tax Liabilities		
Other	**---**	(1.6)
Total Current Accrued Income Tax Liabilities	**---**	(1.6)
Current Deferred Income Tax Assets, net	**$ 18.7**	$ 39.8
Non-Current Deferred Income Tax Liabilities		
Accelerated depreciation and other property related differences	**$ 1,071.4**	$ 1,325.6
Investment in Enogex Holdings	**376.1**	---
Company pension plan	**71.4**	51.3
Derivative instruments	**22.4**	---
Regulatory asset	**17.2**	0.2
Income taxes refundable to customers, net	**16.8**	7.4
Bond redemption-unamortized costs	**4.8**	5.2
Total Non-Current Deferred Income Tax Liabilities	**1,580.1**	1,389.7
Non-Current Deferred Income Tax Assets		
Regulatory liabilities	**(43.7)**	(51.1)
Postretirement medical and life insurance benefits	**(39.0)**	(52.5)
State tax credits	**(35.5)**	(29.9)
Federal tax credits	**(21.5)**	---
Deferred Federal investment tax credits	**(3.6)**	(5.1)
Derivative instruments	**---**	(3.4)
Other	**(2.0)**	(1.1)
Total Non-Current Deferred Income Tax Assets	**(145.3)**	(143.1)
Non-Current Deferred Income Tax Liabilities, net	**$ 1,434.8**	$ 1,246.6

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

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

In September 2010, the Small Business Jobs and Credit Act of 2010 was signed into law, which included accelerated tax depreciation provisions allowing the Company to record a current income tax deduction for 50 percent of the cost of certain property placed into service from January 1, 2010 to September 7, 2010. For financial accounting purposes, the

Company recorded an increase in Non-Current Deferred Income Taxes Liability at September 30, 2010 on the Company's Consolidated Balance Sheet to recognize the financial statement impact of this new law. In December 2010, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act was signed into law, which included accelerated tax depreciation provisions allowing the Company to record a current income tax deduction for 100 percent of the cost of certain property acquired and placed into service from September 8, 2010 to December 31, 2011. The new law will also allow the Company to record a current income tax deduction for 50 percent of the cost of certain property placed into service from January 1, 2012 to December 31, 2012. For financial accounting purposes, the Company recorded an increase in Non-Current Deferred Income Taxes Liability at December 31, 2010 on the Company's Consolidated Balance Sheet to recognize the financial statement impact of this new law.

Medicare Part D Subsidy

The Health Care Reform Acts effectively change the tax treatment of Federal subsidies paid to sponsors of retiree health benefit plans that provide prescription drug benefits that are at least actuarially equivalent to the corresponding benefits provided under Medicare Part D.

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

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

Other

The Company had a Federal renewable energy tax credit carryover from 2009 of $17.2 million with an additional $15.5 million in credits being generated during 2010. The Company currently believes that $11.2 million of these Federal tax credit amounts will be utilized in the 2010 tax year with $21.5 million being carried over to 2011 and later tax years. In addition, the Company has an Oklahoma tax credit carryover from 2009 of $44.1 million. During 2010, additional Oklahoma tax credits of $24.2 million were generated or purchased by the Company. The Company currently believes that $16.0 million of these state tax credit amounts will be utilized in the 2010 tax year with $52.3 million being carried over to 2011 and later tax years. These Federal and state tax credits will begin to expire in 20 19; however, the Company expects that all Federal and state tax credits will be fully utilized prior to expiration.

9. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

The Company issued 346,456 shares of common stock under its DRIP/DSPP in 2010 and received proceeds of $13.8 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, 2010, there were 2,646,288 shares of unissued common stock reserved for issuance under the Company's DRIP/DSPP.

Shareowners Rights Plan

The Shareowners Rights Plan expired by its terms on December 11, 2010.

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

EPS

Outstanding shares for purposes of basic and diluted EPS were calculated as follows:

Year ended December 31 *(In millions)*	**2010**	2009	2008
Average Common Shares Outstanding			
Basic average common shares outstanding	**97.3**	96.2	92.4
Effect of dilutive securities:			
Employee stock options and unvested stock grants	**---**	---	0.1
Contingently issuable shares (performance units)	**1.6**	1.0	0.3
Diluted average common shares outstanding	**98.9**	97.2	92.8
Anti-dilutive shares excluded from EPS calculation	---	---	---

10. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2010, the Company was in compliance with all of its debt agreements.

OG&E has tax-exempt pollution control bonds with optional redemption provisions that allow the holders to request repayment of the bonds at various dates prior to the maturity. The bonds, which can be tendered at the option of the holder during the next 12 months, are as follows:

SERIES	DATE DUE	AMOUNT
		(In millions)
0.30% - 0.50%	Garfield Industrial Authority, January 1, 2025	**$ 47.0**
0.35% - 0.52%	Muskogee Industrial Authority, January 1, 2025	**32.4**
0.33% - 0.55%	Muskogee Industrial Authority, June 1, 2027	**56.0**
Total (redeemable during next 12 months)		**$ 135.4**

All of these bonds are subject to an optional tender at the request of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase. The bond holders, on any business day, can request repayment of the bond by delivering an irrevocable notice to the tender agent stating the principal amount of the bond, payment instructions for the purchase price and the business day the bond is to be purchased. The repayment option may only be exercised by the holder of a bond for the principal amount. When a tender notice has been received by the trustee, a third party remarketing agent for the bonds will attempt to remarket any bonds tendered for purchase. This process occurs once per week. Since the original issuance of these series of b onds 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 $25.0 million and $300.0 million in years 2013 and 2014, respectively. There are no maturities of the Company's long-term debt in years 2011, 2012 or 2015.

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.

Issuance of OG&E Long-Term Debt

On June 8, 2010, OG&E issued $250 million of 5.85% senior notes due June 1, 2040. The proceeds from the issuance were added to the Company's general funds and were used to fund OG&E's ongoing capital expenditure program and for working capital. OG&E expects to issue additional long-term debt from time to time when market conditions are favorable and when the need arises.

11. Short-Term Debt and Credit Facilities

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $145.0 million and $175.0 million at December 31, 2010 and 2009, respectively, at a weighted-average interest rate of 0.34 percent and 0.27 percent, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at December 31, 2010.

Revolving Credit Agreements and Available Cash

Entity	Aggregate Commitment	Amount Outstanding (A)	Weighted-Average Interest Rate	Maturity
	(In millions)			
OGE Energy (B)	$ 596.0	$ 145.0	0.34% (D)	December 6, 2012
OG&E (C)	389.0	0.3	0.33% (D)	December 6, 2012
Enogex LLC (E)	250.0	25.0	0.57% (D)	March 31, 2013
	1,235.0	170.3	0.38%	
Cash	2.3	N/A	N/A	N/A
Total	$ 1,237.3	$ 170.3	0.38%	

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 31, 2010.
(B) This bank facility is available to back up OGE Energy's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At December 31, 2010, there was $145.0 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, 2010, there was $0.3 million supporting letters of credit.
(D) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit.
(E) This bank facility is available to provide revolving credit borrowings for Enogex LLC. As Enogex LLC's credit agreement matures on March 31, 2013 along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Consolidated Balance Sheets.

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

Unlike OGE Energy and Enogex, OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2011 and ending December 31, 2012.

12. Retirement Plans and Postretirement Benefit Plans

Defined Benefit Pension Plan and Restoration of Retirement Income Plan

In October 2009, the Company's Pension Plan and the Company's 401(k) Plan were amended, effective January 1, 2010 to provide eligible employees a choice to select a future retirement benefit combination from the Company's Pension Plan and the Company's 401(k) Plan.

Employees hired or rehired on or after December 1, 2009 do not participate in the Pension Plan but are eligible to participate in the 401(k) Plan where, for each pay period, the Company contributes 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. During each of 2010 and 2009, the Company made contributions to its Pension Plan of $50 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. During 2011, the Company may contribute up to $50 million to its Pension Plan. The expected contribution to the Pension

Plan during 2011 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. 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.

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 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 following table presents the status of the Company's Pension Plan and Restoration of Retirement Income Plan at December 31, 2010 and 2009. 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.

	Pension Plan		Restoration of Retirement Income Plan	
December 31 *(In millions)*	**2010**	2009	**2010**	2009
Benefit obligations	**$ (640.9)**	$ (610.9)	**$ (10.8)**	$ (8.3)
Fair value of plan assets	**574.0**	496.3	**---**	---
Funded status at end of year	**$ (66.9)**	$ (114.6)	**$ (10.8)**	$ (8.3)

The following table summarizes the benefit payments the Company expects to pay related to its Pension Plan and Restoration of Retirement Income Plan. 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.

(In millions)	Projected Benefit Payments
2011	$ 59.5
2012	63.6
2013	79.7
2014	79.0
2015	72.7
2016 and Beyond	308.8

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 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 investments:

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 m anager is evaluated against:

Asset Class	Comparative Benchmark(s)
Fixed Income	Barclays Capital Aggregate Index
Equity Index	Standard and Poor's 500 Index
Value Equity	Russell 1000 Value Index – Short-term
	Standard and Poor's 500 Index – Long-term
Growth Equity	Russell 1000 Growth Index – Short-term
	Standard and Poor's 500 Index – Long-term
Mid-Cap Equity	Standard and Poor's 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. 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 Standard and Poor's 400 Midcap Index, small dividend yield, return on equity at or near the Standard and Poor's 400 Midcap Index and an EPS growth rate at or near the Standard and Poor's 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 an EPS 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 Far East Index is the benchmark for comparative performance purposes. The Morgan Stanley Capital International Europe, Australia and Far East In dex 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 Company's 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 ma rket 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 Investments

The following tables summarize the Pension Plan's investments that are measured at fair value on a recurring basis at December 31, 2010 and 2009. There were no Level 3 investments held by the Pension Plan at December 31, 2010 and 2009.

(In millions)	December 31, 2010	Level 1	Level 2
Common stocks			
U.S. common stocks	**$ 189.0**	**$ 189.0**	**$ ---**
Foreign common stocks	**75.9**	**75.9**	**---**
Bonds, debentures and notes (A)			
Corporate fixed income and other securities	**105.5**	**---**	**105.5**
Mortgage-backed securities	**26.5**	**---**	**26.5**
U.S. Government obligations			
Mortgage-backed securities	**76.5**	**---**	**76.5**
U.S. treasury notes and bonds (B)	**35.7**	**35.7**	**---**
Other securities	**2.4**	**---**	**2.4**
Commingled fund (C)	**37.7**	**---**	**37.7**
Common collective trust (D)	**23.1**	**---**	**23.1**
Foreign government bonds	**2.6**	**---**	**2.6**
Mutual funds			
U.S. equity mutual funds	**3.4**	**3.4**	**---**
Foreign equity mutual fund	**1.0**	**1.0**	**---**
U.S. municipal bonds	**4.3**	**---**	**4.3**
Preferred stocks (foreign)	**0.7**	**0.7**	**---**
Commitment to purchase securities	**3.7**	**---**	**3.7**
Interest-bearing cash	**0.2**	**0.2**	**---**
Total Plan investments	**$ 588.2**	**$ 305.9**	**$ 282.3**
Receivable from broker for securities sold	**5.5**		
Interest and dividends receivable	**2.8**		
Payable to broker for securities purchased	**(22.5)**		
Total Plan assets	**$ 574.0**		

(In millions)	December 31, 2009	Level 1	Level 2
Common stocks			
U.S. common stocks	$ 152.7	$ 152.7	$ ---
Foreign common stocks	57.2	57.2	---
Bonds, debentures and notes (A)			
Corporate fixed income and other securities	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
Mutual funds			
Foreign equity mutual funds	2.0	2.0	---
U.S. bond mutual funds	0.8	0.8	---
U.S. municipal bonds	2.5	---	2.5
Preferred stocks (foreign)	0.9	0.9	---
Interest-bearing cash	0.4	0.4	---
Forward contracts	(0.1)	---	(0.1)
Total Plan investments	$ 496.9	$ 236.2	$ 260.7
Receivable from broker for securities sold	5.4		
Interest and dividends receivable	2.5		
Payable to broker for securities purchased	(8.5)		
Total Plan assets	$ 496.3		

(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 certain 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 are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible by the Pension Plan and postretirement benefit plans at the measurement date.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the Pension Plan and postretirement benefit plans own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members. 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. Effective January 1, 2010, the age for dependents to participate in the Company's Medical Plan was increased to age 21 and if the dependent is a full-time student to age 26. Effective July 1, 2010, the age for dependents to participate in the Company's Medical Plan was increased to age 26 regardless of whether or no t the dependent is a full-time student. 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.

At the beginning of January 2011, the Company adopted several amendments to the retiree medical plan. Effective January 1, 2012, medical costs for pre-65 aged eligible retirees will be fixed at the 2011 level and the Company will cover future annual medical inflationary cost increases up to five percent. Increases in excess of five percent annually will be covered by the pre-65 aged retiree in the form of premium increases. Also, effective January 1, 2012, the Company will supplement Medicare coverage for Medicare-eligible retirees, providing them a fixed stipend based on the Company's expected average 2011 premium for medical and drug coverage, and allow those Medicare-eligible retirees to acquire coverage from a Company-provided third-party administrator. The effect of these plan amendments will be reflected in the Company's March 31, 2011 Consolidated Balance Sheet as a reduction to the postretirement benefit obligation of $91.3 million, an increase in other comprehensive income of $16.9 million and a reduction to OG&E's benefit obligations regulatory asset of $74.4 million.

Plan Investments

The following tables summarize the postretirement benefit plans investments that are measured at fair value on a recurring basis at December 31, 2010 and 2009. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2010 and 2009.

(In millions)	December 31, 2010	Level 1	Level 3
Group retiree medical insurance contract (A)	**$ 53.2**	**$ ---**	**$ 53.2**
U.S. equity mutual funds	**5.5**	**5.5**	---
Money market fund	**0.6**	**0.6**	---
Total Plan investments	**$ 59.3**	**$ 6.1**	**$ 53.2**

(In millions)	December 31, 2009	Level 1	Level 3
Group retiree medical insurance contract (A)	$ 49.3	$ ---	$ 49.3
U.S. equity mutual funds	4.9	4.9	---
Cash	0.8	0.8	---
Total Plan investments	$ 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.

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 summarizes 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)*	**2010**	2009
Balance at January 1	**$ 49.3**	$ 55.1
Actual return on plan assets relating to investments held at the reporting date	**3.9**	(5.8)
Balance at December 31	**$ 53.2**	$ 49.3

The following table presents the status of the Company's postretirement benefit plans at December 31, 2010 and 2009. 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.

December 31 *(In millions)*	**2010**	2009
Benefit obligations	**$ (337.1)**	$ (288.0)
Fair value of plan assets	**59.3**	55.0
Funded status at end of year	**$ (277.8)**	$ (233.0)

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 8.99 percent in 2011 with the rates trending downward to five percent by 2020. 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)*	**2010**	2009	2008
Effect on aggregate of the service and interest cost components	**$ 3.1**	$ 2.4	$ 2.2
Effect on accumulated postretirement benefit obligations	**0.7**	40.3	28.3

ONE-PERCENTAGE POINT DECREASE

Year ended December 31 *(In millions)*	**2010**	2009	2008
Effect on aggregate of the service and interest cost components	**$ 2.5**	$ 1.9	$ 1.8
Effect on accumulated postretirement benefit obligations	**1.6**	32.9	23.4

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Act, which expanded Medicare to include, for the first time, coverage for prescription drugs. The following table summarizes the gross benefit payments the Company expects to pay related to its postretirement benefit plans, including prescription drug benefits, and the Federal subsidy receipts the Company expects to receive provided by the Medicare Act. The Company received $1.4 million in Federal subsidy receipts in 2010.

(In millions)	Gross Projected Postretirement Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Benefit Payments
2011	$ 14.2	$ 2.2	$ 12.0
2012	14.9	---	14.9
2013	15.6	---	15.6
2014	16.2	---	16.2
2015	16.9	---	16.9
2016 and Beyond	91.1	---	91.1

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 2010 and 2009. 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 APBO. The APBO 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 APBO for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2010 was $601.4 million and $8.7 million, respectively. The APBO for the Pension Plan and the Restoration of Retirement I ncome Plan at December 31, 2009 was $558.3 million and $6.4 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:

	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 *(In millions)*	**2010**	2009	**2010**	2009	**2010**	2009
Change in Benefit Obligation						
Beginning obligations	**$ (610.9)**	$ (547.0)	**$ (8.3)**	$ (7.3)	**$ (288.0)**	$ (234.3)
Service cost	**(16.7)**	(18.1)	**(0.9)**	(0.7)	**(4.3)**	(3.3)
Interest cost	**(31.8)**	(31.4)	**(0.5)**	(0.4)	**(17.0)**	(14.1)
Plan amendments	**---**	(10.2)	**---**	(0.5)	**---**	---
Plan curtailments	**---**	0.4	**---**	---	**---**	---
Participants' contributions	**---**	---	**---**	---	**(7.3)**	(6.8)
Medicare subsidies received	**---**	---	**---**	---	**(1.4)**	---
Actuarial gains (losses)	**(15.9)**	(39.3)	**(1.5)**	0.1	**(36.6)**	(45.2)
Benefits paid	**34.4**	34.7	**0.4**	0.5	**17.5**	15.7
Ending obligations	**$ (640.9)**	$ (610.9)	**$ (10.8)**	$ (8.3)	**$ (337.1)**	$ (288.0)
Change in Plans' Assets						
Beginning fair value	**$ 496.3**	$ 389.9	**$ ---**	$ ---	**$ 55.0**	$ 57.0
Actual return on plans' assets	**62.1**	91.1	**---**	---	**6.0**	(7.3)
Employer contributions	**50.0**	50.0	**0.4**	0.5	**7.1**	14.2
Participants' contributions	**---**	---	**---**	---	**7.3**	6.8
Medicare subsidies received	**---**	---	**---**	---	**1.4**	---
Benefits paid	**(34.4)**	(34.7)	**(0.4)**	(0.5)	**(17.5)**	(15.7)
Ending fair value	**574.0**	496.3	**---**	---	**59.3**	55.0
Funded status at end of year	**$ (66.9)**	$ (114.6)	**$ (10.8)**	$ (8.3)	**$ (277.8)**	$ (233.0)

Net Periodic Benefit Cost

	Pension Plan			Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31 *(In millions)*	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Service cost	**$ 16.7**	$ 18.1	$ 19.0	**$ 0.9**	$ 0.7	$ 0.8	**$ 4.3**	$ 3.3	$ 3.7
Interest cost	**31.8**	31.4	31.4	**0.5**	0.4	0.4	**17.0**	14.1	13.4
Expected return on plan assets	**(42.4)**	(33.0)	(43.7)	---	---	---	**(6.9)**	(6.5)	(6.5)
Amortization of transition obligation	---	---	---	---	---	---	**2.7**	2.7	2.7
Amortization of net loss	**21.3**	23.5	9.3	**0.3**	0.3	0.3	**12.1**	5.0	4.0
Amortization of unrecognized prior service cost	**2.4**	0.8	0.9	**0.7**	0.6	0.6	---	1.0	1.9
Net periodic benefit cost (A)	**$ 29.8**	$ 40.8	$ 16.9	**$ 2.4**	$ 2.0	$ 2.1	**$ 29.2**	$ 19.6	$ 19.2

(A) In addition to the $32.2 million, $42.8 million and $19.0 million of net periodic benefit cost recognized in 2010, 2009 and 2008, respectively, the Company recognized the following:

- Ÿ an increase in pension expense in 2010 of $8.1 million, a reduction in pension expense in 2009 of $2.2 million and an increase in pension expense in 2008 of $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
- Ÿ a reduction in pension expense in 2009 of $3.2 million in the Arkansas jurisdiction to reflect the approval of recovery of OG&E's 2006 and 2007 pension settlement costs in the May 2009 Arkansas rate order which are identified as Deferred Pension Plan Expenses (see Note 1).

The capitalized portion of the net periodic pension benefit cost was $6.5 million, $8.4 million and $4.0 million at December 31, 2010, 2009 and 2008, respectively. The capitalized portion of the net periodic postretirement benefit cost was $6.5 million, $4.1 million and $4.6 million at December 31, 2010, 2009 and 2008, respectively.

Rate Assumptions

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31	**2010**	2009	2008	**2010**	2009	2008
Discount rate	**5.30%**	5.30%	6.25%	**5.30%**	6.00%	6.25%
Rate of return on plans' assets	**8.50%**	8.50%	8.50%	**8.50%**	8.50%	8.50%
Compensation increases	**4.40%**	4.50%	4.50%	**N/A**	N/A	N/A
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**8.99%**	9.49%	9.00%
Ultimate trend rate	**N/A**	N/A	N/A	**5.00%**	5.00%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2020**	2018	2014

N/A - not applicable

The overall expected rate of return on plan assets assumption remained at 8.50 percent in 2009 and 2010 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 APBO. 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 $2.1 million and $2.2 million at December 31, 2010 and 2009, 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 also allows an eligible automatic contribution arr angement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants 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 401(k) Plan was amended in October 2009, as discussed previously, whereby employees were offered a choice to either stay in the 401(k) Plan (prior to it being amended) where the Company matching contributions are discussed below or select an option whereby, effective January 1, 2010, the Company contributes 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 401(k) Plan (prior to it being amended), 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 401(k) Plan (prior to it being amended), 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 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 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 contributed $11.4 million, $9.3 million and $8.6 million in 2010, 2009 and 2008, 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 provided to eligible employees 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 SERP 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 SERP is intended to be an unfunded plan and not subject to the benefit limits imposed by the Code.

13. Report of Business Segments

The Company's business is divided into four segments for financial reporting purposes. These segments are as follows: (i) electric utility, which is engaged in the generation, transmission, distribution and sale of electric energy, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. Other Operations primarily included the operations of the holding company. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. In reviewing its segment operating results, the Company focuses on operating income as its measure of segment profit and loss, and, therefore has presented this information below. The following tables summarize the resul ts of the Company's business segments for the years ended December 31, 2010, 2009 and 2008.

2010 *(In millions)*	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	**$ 2,109.9**	**$ 403.6**	**$ 1,005.6**	**$ 798.5**	**$ ---**	**$ (600.7)**	**$ 3,716.9**
Cost of goods sold	**1,000.2**	**246.4**	**733.3**	**804.7**	**---**	**(597.2)**	**2,187.4**
Gross margin on revenues	**1,109.7**	**157.2**	**272.3**	**(6.2)**	**---**	**(3.5)**	**1,529.5**
Other operation and maintenance	**418.1**	**48.9**	**91.5**	**8.4**	**(13.6)**	**(3.5)**	**549.8**
Depreciation and amortization	**208.7**	**21.8**	**50.5**	**0.1**	**11.3**	**---**	**292.4**
Taxes other than income	**69.2**	**13.9**	**6.4**	**0.3**	**3.6**	**---**	**93.4**
Operating income (loss)	**$ 413.7**	**$ 72.6**	**$ 123.9**	**$ (15.0)**	**$ (1.3)**	**$ ---**	**$ 593.9**
Total assets	**$ 5,898.1**	**$ 2,008.6**	**$ 973.8**	**$ 94.5**	**$ 2,701.6**	**$ (4,007.5)**	**$ 7,669.1**
Capital expenditures	**$ 603.4**	**$ 70.2**	**$ 164.0**	**$ 2.4**	**$ 14.1**	**$ (2.4)**	**$ 851.7**

2009 *(In millions)*	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
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	187.7	21.3	45.8	0.1	10.8	---	265.7
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	$ 1,631.7	$ 866.1	$ 125.2	$ 2,685.4	$ (3,519.8)	$ 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	37.5	0.2	7.7	---	217.9
Taxes other than income	59.7	12.7	4.6	0.4	3.1	---	80.5
Operating income	$ 278.3	$ 67.8	$ 117.4	$ 6.4	$ (8.8)	$ 1.0	$ 462.1
Total assets	$ 4,851.2	$ 1,305.0	$ 836.9	$ 235.1	$ 2,469.1	$ (3,178.8)	$ 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 $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.

14. 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)*	2011	2012	2013	2014	2015	2016 and Beyond	Total
Operating lease obligations							
OG&E railcars	$ 3.2	$ 3.1	$ 3.0	$ 3.0	$ 2.9	$ 28.8	$ 44.0
Enogex noncancellable operating leases	2.4	1.0	---	---	---	---	3.4
Total operating lease obligations	$ 5.6	$ 4.1	$ 3.0	$ 3.0	$ 2.9	$ 28.8	$ 47.4

Payments for operating lease obligations were $9.4 million, $9.2 million and $7.3 million in 2010, 2009 and 2008, respectively.

OG&E Railcar Lease Agreement

OG&E has 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. On December 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximu m of $24.0 million.

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

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

Other Purchase Obligations and Commitments

The Company's other future purchase obligations and commitments estimated for the next five years are as follows:

(In millions)	2011	2012	2013	2014	2015	Total
Other purchase obligations and commitments						
OG&E cogeneration capacity and fixed operation and maintenance payments	$ 92.5	$ 90.0	$ 88.0	$ 85.2	$ 82.9	$ 438.6
OG&E expected cogeneration energy payments	61.9	60.5	60.2	67.7	77.0	327.3
OG&E minimum fuel purchase commitments	274.8	134.0	140.7	---	---	549.5
OG&E expected wind purchase commitments	41.6	51.1	51.4	51.9	52.3	248.3
OG&E long-term service agreements	15.7	1.5	9.0	25.4	8.3	59.9
OER Cheyenne Plains commitments	5.4	5.4	6.5	6.5	1.6	25.4
OER MEP commitments	2.1	2.1	2.1	0.9	---	7.2
OER other commitments	3.0	0.7	---	---	---	3.7
Total other purchase obligations and commitments	$ 497.0	$ 345.3	$ 357.9	$ 237.6	$ 222.1	$ 1,659.9

Public Utility Regulatory Policy Act of 1978

At December 31, 2010, OG&E has QF contracts having terms of 15 to 32 years. These contracts were entered into pursuant to 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 320 MW AES-Shady Point, Inc. QF contract and the 120 MW PowerSmith Cogeneration Project, L.P. QF contract, OG&E purchases 100 percent of the electricity generated by the QFs.

For the years ended December 31, 2010, 2009 and 2008, OG&E made total payments to cogenerators of $147.3 million, $139.8 million and $152.8 million, respectively, of which $80.7 million, $83.1 million and $84.4 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.

OG&E Minimum Fuel Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of $352.2 million, $358.8 million and $257.6 million for the years ended December 31, 2010, 2009 and 2008, respectively. 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 Centennial wind farm, (ii) the OU Spirit wind farm, (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 and (iv) access to up to 150 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with CPV Keenan that expires in 2030.

OG&E also received approval on January 5, 2010 from the OCC for a wind power purchase agreement with a wind developer who is to build a new 130 MW wind farm in northwestern Oklahoma. OG&E intends to add this capability to its power-generation portfolio during the second quarter of 2011. Under the terms of the agreement, Edison Mission Energy is to build a 130 MW facility in Dewey County near Taloga. The agreement is a 20-year power purchase agreement, under which the developer is to build, own and operate the wind generating facility and OG&E will purchase its electric output. See Note 15 for further discussion.

OG&E purchased wind power from FPL Energy of $3.9 million, $4.0 million and $4.4 million for the years ended December 31, 2010, 2009 and 2008, respectively, and OG&E purchased wind power from CPV Keenan of $3.8 million for the year ended December 31, 2010.

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.

In September 2008, OG&E acquired a 51 percent interest in the Redbud 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 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 Plant is used.

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

In 2004, OER entered into an FTSA with Cheyenne Plains, who operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas, for 60,000 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 $7.4 million. Effective March 1, 2007, OER and Cheyenne Plains amended the FTSA to provide for OER to turn back 20,000 Dth/day of its capacity beginning in January 2008 for the remainder of the term. OER's new demand fee obligations, net of this turn back and other immaterial release agreements, are disclosed in the table above.

Agreement with Midcontinent Express Pipeline, LLC

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 43 miles of 24-inch steel pipe in Woods and Major counties in Oklahoma, and added 24,000 horsepower of electric-driven compression in Benningt on, Oklahoma. Enogex's capital expenditures allocated to its support of the MEP lease agreement were $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. Accordingly, Enogex proceeded with the construction of facilities necessary to implement this service. On August 25, 2008, a 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. & #160;The Court of Appeals heard arguments of the parties on October 15, 2010. Enogex cannot predict what action the court will take or the timing of that action.

In 2009, OER 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 $2.1 million. OER's demand fee obligations are disclosed in the table above.

OG&E Wholesale Agreement

On May 28, 2009, OG&E sent a termination notice to the Arkansas Valley Electric Cooperative that OG&E would terminate its wholesale power agreement to all points of delivery where OG&E sells or has sold power to the Arkansas

Valley Electric Cooperative, effective November 30, 2011. In December 2010, OG&E and the Arkansas Valley Electric Cooperative entered into a new wholesale power agreement whereby OG&E will supply wholesale power to the Arkansas Valley Electric Cooperative through June 2015. On January 3, 2011, OG&E submitted this agreement to the FERC for approval. OG&E has requested the FERC make this agreement effective the later of either (i) March 1, 2011, the date on which agreements providing for all necessary transmission service have been made effective or (ii) the first day of the month immediately following the date on which the Arkansas Valley Electric Cooperative receives approval of the agreement from the Rural Utilities Services, the division of the U.S. Department of Agriculture responsible for approving electric utility contracts.

Natural Gas Commitments

In August 2010, OG&E issued an RFP for gas supply purchases for periods from November 2010 through March 2011. The gas supply purchases from January through March 2011 account for 21 percent of OG&E's projected 2011 natural gas requirements. The RFP process was completed in September 2010. The contracts resulting from this RFP are tied to various gas price market indices that will expire in 2011. Additional gas supplies to fulfill the OG&E's remaining 2011 natural gas requirements will be acquired through additional RFPs in early to mid-2011, along with monthly and daily purchases, all of which are expected to be made at market prices.

Natural Gas Measurement Cases

Will Price, et al. v. El Paso Natural Gas Co., et al. (Price I). On September 24, 1999, various subsidiaries of the Company were served with a class action petition filed in the District Court of Stevens County, Kansas by Quinque Operating Company and other named plaintiffs alleging the mismeasurement of natural gas on non-Federal lands. On April 10, 2003, the court entered an order denying class certification. On May 12, 2003, the plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended class action petition, and the court granted the motion on July 28, 2003. In its amended petition, OG&E and Enogex Inc. were omitted from the case but two of the Company's other subsidiary entities remained as defendants. The plaintiffs' amended petition seeks class certification and alleges that 60 defendants, including two of the Company's subsidiary entities, have improperly measured the volume of natural gas. The 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.

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 March 31, 2010, the court denied the plaintiffs' request for rehearing.

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

Will Price, et al. v. El Paso Natural Gas Co., et al. (Price II). On May 12, 2003, the plaintiffs (same as those in the 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 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. 0;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.

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 March 31, 2010, the court denied the plaintiffs' request for rehearing.

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

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, plus attorneys' fees and costs, and punitive damages. Enogex an d 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 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 America, Inc. and BP America Production Company'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. After the incident, Enogex coordinated and assisted the affected residents. Enogex resolved matters with two of the residents and Enogex continued to seek resolution with a remaining resident. This resident filed a legal action in May 2009 in the District Court of Cleveland County, Oklahoma, against OGE Energy and Enogex. This matter was resolved by the parties on April 8, 2010. The ultimate resolution of this incident was not material to the Company in light of previously established reserves and insurance coverage. The Company now considers this case closed.

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 had 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 described $2.7 million in take-or-pay damages (including interest) and $36 million in contract repudiation damages (including interest), subject to the limitation described below. In 2001, OG&E agreed to provide the plaintiffs with $5.8 million of consideration and the parties agreed to arbitrate the dispute. On May 19, 2010, the arbitration panel issued an arbitration award in an amount less than the consideration previously paid by OG&E and, as a result, OG&E did not owe any additional amount. The Company now considers this case closed.

Franchise Fee Lawsuit

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

September 13, 2010, the Oklahoma Supreme Court issued a writ prohibiting the District Court judge from proceeding further in this case except to dismiss the case. On September 20, 2010, the plaintiffs filed a motion to reconsider this matter with the Oklahoma Supreme Court. On December 6, 2010 the Oklahoma Supreme Court denied the plaintiffs motion to reconsider. In compliance with the Oklahoma Supreme Court order, on December 14, 2010, the District Court of Creek County dismissed the lawsuit. OG&E considers this matter closed.

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 their wastes, requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. 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.

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 is expected to increase the cost of conducting business.

Air

Acid Rain and Sulfur Dioxide Air Quality Standards

The Federal Clean Air Act includes an acid rain program to reduce SO2 emissions. Reductions were obtained through a program of emission (release) allowances issued by the EPA to power plants covered by the acid rain program. Each allowance 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 2010, OG&E's SO2 emissions were below the allowable limits.

OG&E sold 34,000 banked allowances in 2010 for $2.3 million. Also, during 2010, OG&E received proceeds of less than $0.1 million from the annual EPA spot (year 2010) and seven-year advance (year 2017) allowance auctions that were held in March 2010.

Nitrogen Oxides Air Quality Standards

On January 25, 2010, the EPA released a rule strengthening the NAAQS for oxides of nitrogen as measured by nitrogen dioxide 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 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 2010 were 0.336 lbs/MMBtu.

Particulate Matter Air Quality Standards

On September 21, 2006, the EPA lowered the 24-hour fine particulate NAAQS while retaining the annual NAAQS at its existing 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 Air Quality Standards

Currently, the EPA has designated Oklahoma "in attainment" with the NAAQS for ozone of 0.08 parts per million. In March 2008, the EPA lowered the ambient primary and secondary standards to 0.075 parts per million. Oklahoma had until March 2009 to designate any areas of non-attainment within the state, based on ozone levels in 2006 through 2008. Before the designations were complete, the EPA announced that it 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 and extended the deadline for promulgating initial area designations for the NAAQS to March 12, 2011.

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 EPA has indicated that it expects to issue a final standard by July 2011. In the proposed rule, the EPA set forth an accelerated schedule for implementing a revised ozone NAAQS that could impose compliance deadlines ranging from 2014 to 2031. The Company cannot predict the final outcome of this proposed revision to the ozone NAAQS or its affect on OG&E's or Enogex's operations.

Climate Change and Greenhouse Gas Emissions

Emissions of greenhouse gases, including carbon dioxide, sulfur hexafluoride and methane, may be contributing to warming of the Earth's atmosphere. There are various international agreements that restrict greenhouse gas emissions, but none of them have a binding effect on sources located in the United States. The U.S. Congress has not passed legislation to reduce emissions of greenhouse gases and the future prospects for any such legislation are uncertain. Several states 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. Oklahoma, Arkansas and Texas are not among them.

In the absence of Federal legislation, the EPA is taking steps to regulate greenhouse gas emissions from stationary sources using existing legal authority. 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 reporting requirements apply to 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. For petroleum and natural gas facilities, data collection begins on January 1, 2011, w ith the first annual report due on March 31, 2012. OG&E already 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, offsetting or sequestering its carbon dioxide emissions.

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 NAAQS. Oklahoma submitted a demonstration to the EPA that the state does not affect air quality in downwind states. Air quality modeling conducted by the EPA indicated that the state's demonstration was not sufficient for NOX emissions. On July 6, 2010, the EPA proposed a rule that would require thirty one states and the District of Columbia to reduce power plant emissions that contribute to ozone and fine particulate pollution in neighboring states. Pursuant to this proposed rule, Oklahoma is required to reduce NOX emissions from sources within the state du ring ozone season (May through September). The EPA is currently considering alternative approaches for achieving the reductions set forth in the proposed rule, including methods on how to allocate emissions allowances. The Company commented on the proposed rule and is monitoring its status. Until final rules are issued, the impact of these proposals on the Company cannot be determined.

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 is cooperating with the EPA and is seeking to demonstrate that OG&E is in compliance with the Federal Clean Air Act and new source review process. 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, 2010, 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 $0.9 million in 2010 and for Enogex's facilities were $0.2 million in 2010.

Waste

OG&E has sought and will continue to seek pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2010, OG&E obtained refunds of $3.1 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

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 that rejected portions of previous rules and confirmed that the 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 OG&E's request, Oklahoma will not require implementation of 316(b) requirements prior to the EPA developing and finalizing their rules, although the state has required OG&E to implement best management practices for existing water intakes as a condition to renewal of several water permits. 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.

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 GAAP, 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 15 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 pen ding or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

15. Rate Matters and Regulation

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, 2010, 88 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and four 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 f or the protection of utility customers with respect to the FERC jurisdictional rates.

Completed Regulatory Matters

OG&E OU Spirit Wind Power Project

As previously disclosed, on November 25, 2009, OG&E received an order from the OCC authorizing OG&E to recover from Oklahoma customers the cost to construct OU Spirit, with the rider being implemented on December 4, 2009. In January 2008, OG&E filed with the SPP for an interconnection agreement for the OU Spirit project. On May 29, 2009, OG&E executed an interim interconnection agreement, allowing OU Spirit to interconnect to the transmission grid, subject to certain conditions. On August 27, 2009, the FERC issued an order accepting the interim interconnection agreement, subject to certain conditions, which enables OU Spirit to interconnect into the transmission grid. On February 8, 2011, the final interconnection agreement was put in place.

On January 19, 2011, the APSC issued an order finding that (i) OU Spirit is prudent and is in the public's interest and (ii) the $2.1 million of costs associated with OU Spirit from September 1, 2010 through June 30, 2011 should be recovered through the Energy Cost Recovery rider, which is expected to be filed with the APSC by March 15, 2011 (beginning July 1, 2011, OU Spirit costs are expected to be recovered in base rates resulting from OG&E's 2010 Arkansas rate case).

OG&E Renewable Energy Filing

In September 2009, OG&E reached agreements with two developers who are to build two new wind farms, totaling 280 MWs, in northwestern Oklahoma. Under the terms of the agreements, CPV Keenan built a 150 MW wind farm in Woodward County, which was placed in service in December 2010, and Edison Mission Energy is to build a 130 MW facility in Dewey County near Taloga, which is expected to be in service during the second quarter of 2011. 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 217;s fuel adjustment clause. OG&E will continue to evaluate renewable opportunities to add to its power-generation portfolio in the future.

On January 19, 2011, the APSC issued an order finding that the 280 MW wind power purchase agreements are prudent and should be recovered through the Energy Cost Recovery rider.

OG&E Windspeed Transmission Line Project

The OCC approved OG&E's request to recover construction costs of up to $218 million, including AFUDC, for Windspeed. Construction costs and AFUDC incurred for Windspeed were $212.3 million. Windspeed was placed into service on March 31, 2010, with the recovery rider being implemented with the first billing cycle in April 2010.

OG&E Long-Term Gas Supply Agreements

In May 2010, the OCC approved OG&E's request for a waiver of the competitive bid rules to allow OG&E to negotiate desired long-term gas purchase agreements. On June 29, 2010, OG&E filed a separate application with the OCC seeking approval of four long-term gas purchase agreements, which would provide a 12-year supply of natural gas to OG&E and account for 25 percent of its currently projected natural gas fuel supply needs over the same time period. On September 26, 2010, OG&E filed a motion with the OCC to dismiss this case. A hearing in this matter was held on October 7, 2010 and the administrative law judge recommended that the case be dismissed without prejudice. OG&E and the other parties to this matter continue ongoing discussions with the OCC Staff.

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

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

OG&E Smart Grid Project

Several provisions of the ARRA relate to issues of direct interest to the Company including, in particular, financial incentives to develop smart grid technology, transmission infrastructure and renewable energy. OG&E received a $130 million grant from the DOE to be used for the Smart Grid program in OG&E's service territory.

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

- Pre-approval for system-wide deployment of smart grid technology and authorization for OG&E to begin recovering the costs of the system-wide deployment of smart grid technology through a rider mechanism that will become effective in accordance with the order approving the settlement agreement;
- OG&E's total project costs eligible for recovery (those costs expended or accrued by OG&E prior to the termination of the period authorized by the DOE as eligible for grant funds) shall be capped at $366.4 million, inclusive of the DOE grant award amount. The Smart Grid project cost includes the cost of implementing the Norman, Oklahoma smart grid pilot program previously authorized by the OCC. Under the terms of the settlement, the Smart Grid project cost would be deemed to represent an investment that is fair, just and reasonable and in the public interest and to be prudent and will be recognized in OG&E's 2013 general rate case;
- To the extent that OG&E's total expenditure for system-wide deployment of smart grid technology during the eligible period exceeds the Smart Grid project cost, OG&E shall be entitled to offer evidence and seek to establish that the excess above the Smart Grid project cost was prudently incurred and any such contention may be addressed in OG&E's 2013 rate case;
- Implementation of the recovery rider would commence with the first billing cycle in July 2010;
- Continued utilization of a return on equity previously approved by the OCC for other various recovery riders;
- The recovery rider shall be designed to collect, on a levelized basis, the revenue requirement associated with the estimated project cost of $357.4 million and shall be subject to a true-up in 2014 after the recovery rider expires, including a true-up for project costs, if any, in excess of $357.4 million but less than the Smart Grid project cost. Any over/under recovery remaining will be passed or credited through OG&E's fuel adjustment clause;
- OG&E guarantees that customers will receive the benefit of certain operations and maintenance cost reductions resulting from the smart grid deployment as a credit to the recovery rider;
- Beginning January 1, 2011, OG&E shall make available the smart grid web portal to all customers having a smart meter. OG&E shall expend funds to educate customers regarding the best use of the information available on the portal. In addition, OG&E shall make available to all customers who do not have internet access the opportunity to receive a monthly home energy report. This report shall be made available, free of charge, to customers eligible for the Company's Low Income Home Energy Assistance Program and/or Senior Citizen program who are without internet service. The incremental costs for web portal access, education and the providing of home energy reports free of charge are to be accumulated as a regulatory asset in an amount up to $6.9 million and recovered in base rates beginning in 2014;
- The stranded costs associated with OG&E's existing meters which are being replaced by smart meters will be accumulated in a regulatory asset and recovered in base rates beginning in 2014; and
- OG&E will file an application with the APSC related to the deployment of smart grid technology by the end of 2010.

On December 17, 2010, OG&E filed an application with the APSC requesting pre-approval for system-wide deployment of smart grid technology and a recovery rider, including a credit for the Smart Grid grant. A procedural schedule has not been established in this matter.

OG&E Crossroads Wind Project

In February 2010, OG&E signed memoranda of understanding for 197.8 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with Crossroads. On July 29, 2010, the OCC approved a settlement that would allow OG&E to build, own and operate the wind farm. The key settlement terms approved by the OCC were:

- Authorization for OG&E to begin recovering the costs of Crossroads through a rider mechanism that will be effective until new rates are implemented after OG&E's 2013 general rate case;

- Continued utilization of a return on equity previously approved by the OCC for other various recovery riders, subject to adjustment in the future to reflect the return on equity authorized in subsequent general rate cases;
- OG&E's capital costs for which it is entitled recovery for a 197.8 MW wind farm are $407.7 million;
- To the extent OG&E's total investment in Crossroads exceeds the amount for which it is entitled recovery, OG&E shall be entitled to offer evidence and seek to establish that the excess amount was prudently incurred and should be included in OG&E's rate base; and
- If the three-year rolling average of Crossroads MWHs of production (including a credit for energy not produced due to curtailments or other events caused by system emergencies, force majeure events, or transmission system issues) falls below 712,844 MWHs, OG&E shall file testimony demonstrating the appropriate operation of Crossroads as part of its fuel cost recovery filing.

Pursuant to the terms of the settlement, OG&E chose to expand Crossroads by an additional 29.7 MWs. As a result of the expansion, the amount of capital costs which OG&E is entitled to recover and the three-year rolling average of MWH production were adjusted to $469.7 million and 819,879 MWHs, respectively. The total projected cost of the 227.5 MW expanded project, including AFUDC, is $450 million, which is below the adjusted recovery amount of $469.7 million. OG&E entered into a turbine supply agreement with Siemens whereby OG&E is to acquire 227.5 MWs of wind turbine generation at a cost in excess of $300 million. OG&E expects Crossroads to be in service by the end of 2011.

OG&E is in the process of entering into an interconnection agreement with the SPP for Crossroads. As part of the multi-study interconnection process, the SPP conducted an interim operational study to determine the impact Crossroads will have on the existing transmission system. The SPP verbally indicated that limited interconnection would be necessary to address system stability limitations. In order to enable full interconnection of Crossroads, OG&E put forth a mitigation proposal, consisting of a system protection relay system, which has recently received all the necessary SPP working group and committee approvals to be implemented. This will allow Crossroads to interconnect at the anticipated 227.5 MWs. On December 30, 2010, the SPP posted the results of its interim operatio nal study to reflect the SPP approval of the mitigation strategy. OG&E expects a final interconnection agreement to be put in place by the second quarter of 2011.

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 based on the value of the fuel at the time of usage.

In April 2010, the FERC accepted Enogex's proposed zonal fixed fuel percentages.

Enogex Mid-Year 2010 Fuel Filing

As Enogex anticipated over recovering fuel for the remainder of 2010, Enogex filed a mid-year fuel filing on July 1, 2010. The proposed reduced rates were effective August 1, 2010 and were subject to refund pending FERC approval. Concurrently, Enogex asked the FERC for authority to change the timing of its annual filing to February 15 and for implementation of a new fuel year with a 12-month period of April 1 through March 31. If both requests are approved, the reduced rates will remain in effect until March 31, 2011, at which time new rates for the period from April 1, 2011 to March 31, 2012 will be implemented. On November 23, 2010, the FERC issued an order accepting Enogex's revised fuel factors and approving revisions the timing of the annual fuel filing to February 15 and for implementation of a new fuel year wit h a 12-month period of April 1 through March 31. No refund was required as a result of the revised fuel percentages.

Market-Based Rate Authority

On December 22, 2003, OG&E and OER 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 OER submitted a compliance filing to the FERC that applied the interim tests to OG&E and OER. On June 7, 2005, the FERC issued an order finding that OG&E and OER 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 OER have the ability to exercise market power in OG&E's control area. On August 8, 2005, OG&E and OER 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 OER 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 OER 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 OER'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 OER, and concluded that OG&E and OER satisfy the FERC's generation market power standard for directly interconnected first-tier control a reas. Second, the FERC directed OG&E and OER 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 OER 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 OER file change of status reports and triennial market power reports according to the FERC orders and regulations. In July 2009, OG&E and OER filed a triennial market power update with the FERC which reported that there have been no significant changes to O G&E's and OER's market-based rate authority. On July 21, 2010, the FERC issued an order accepting OG&E's July 2009 triennial market power update and found no change from the previous market-based rate authorizations.

On October 14, 2010, OER filed with the FERC a Notice of Cancellation of OER's market-based rate tariff. OER does not currently make wholesale sales pursuant to its market-based rate authorization, has not done so in several years and does not anticipate doing so in the foreseeable future. Additionally, OER has no outstanding transactions under its market-based rate tariff, so no customers will be affected by the filing. OER also requested a waiver of the prior notice filing requirement to allow termination of its market-based rate tariff effective as of October 13, 2010. On November 22, 2010, the FERC issued an order approving OER's Notice of Cancellation, effective December 13, 2010.

On November 9, 2010, OER filed with the FERC a Notice of Cancellation of OER's cost-based rate tariff. OER does not currently make wholesale sales pursuant to its cost-based rate authorization, has not done so in several years and does not anticipate doing so in the foreseeable future. Additionally, OER has no outstanding transactions under its cost-based rate tariff, so no customers will be affected by the filing. OER also requested a waiver of the prior notice filing requirement to allow termination of its cost-based rate tariff effective as of October 13, 2010. On December 15, 2010, the FERC issued an order approving OER's Notice of Cancellation, effective October 13, 2010.

Tallgrass Joint Venture

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

Pending Regulatory Matters

OG&E 2010 Arkansas Rate Case Filing

On September 28, 2010, OG&E filed a rate case with the APSC requesting a rate increase of $17.7 million, to recover the cost of significant electric system expansions and upgrades, including high-voltage transmission lines and wind energy, that have been completed since the last rate filing in August 2008, as well as rising operating costs. If approved, the targeted implementation date for new electric rates is expected to be during the third quarter of 2011. A hearing in this matter is scheduled for May 24, 2011.

OG&E SPP Cost Tracker

On October 7, 2010, OG&E filed an application with the OCC seeking recovery of the Oklahoma jurisdictional portion of (i) costs associated with transmission upgrades and facilities that have been approved by the SPP in its regional planning processes and constructed by other transmission owners throughout the SPP that have been allocated to OG&E through the FERC-approved transmission rates and (ii) SPP administrative fees. OG&E requested authorization to implement a cost tracker in order to recover from its retail customers the third-party project costs discussed above and to collect its administrative SPP cost assessment levied under Schedule 1A of the SPP open access transmission tariff, which is currently recovered in base rates. OG&E also requested authorization to establish a regulatory asset effective January 1, 2011 in order to give OG&E the opportunity to recover such costs that will be paid but not recovered until the cost tracker is made effective. On February 8, 2011, all parties signed a settlement agreement in this matter which would allow OG&E to begin recovering the incremental transmission costs allocated to OG&E by the SPP for base plan transmission projects built by othe r transmission owners in the SPP through a recovery rider effective January 1, 2011. OG&E anticipates recovering $1.8 million of incremental revenues in 2011 through the rider. OG&E had requested the inclusion of the incremental SPP administrative fee assessment in the recovery rider. Rather than including these costs in the recovery rider, the stipulating parties agreed to allow OG&E to include the projected 2012 level of the SPP administrative fee assessment in its anticipated Oklahoma rate case to be filed in the summer of 2011. A hearing on the settlement is scheduled for February 17, 2011. OG&E expects to receive an order from the OCC in this matter during the second quarter of 2011.

OG&E FERC Transmission Rate Incentive Filing

On October 12, 2010, OG&E submitted to the FERC revised tariff sheets to its open access transmission tariff and to the SPP open access transmission tariff to implement two limited transmission rate incentives. If approved by the FERC, the revised tariff sheets will authorize recovery of 100 percent of all prudently incurred construction work in progress in rate base for specific 345 kV EHV transmission projects to be constructed and owned by OG&E within the SPP's region. In addition, if approved by the FERC, the revised tariff sheets will authorize OG&E to recover 100 percent of all prudently incurred development and construction costs if the transmission projects are abandoned or cancelled, in whole or in part, for reasons beyond OG&E's control. On December 30, 2010, the FERC granted the se two incentives for the Priority Projects discussed below. Also, OG&E plans to make a filing with the FERC in February 2011 to seek the incentives for at least five other projects.

SPP Transmission/Substation Projects

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

There are several studies currently under review at the SPP including a 20-year plan to address issues of regional and interregional importance. The 20-year plan suggests overlaying the SPP footprint with a 345 kV transmission system and integrating it with neighboring regional entities. In 2009, the SPP Board of Directors approved a new report that recommended restructuring the SPP's regional planning processes to focus on the construction of a robust transmission system, large enough in both scale and geography, to provide flexibility to meet the SPP's future needs. OG&E expects to actively participate in the ongoing study, development and transmission growth that may result from the SPP's plans.

In 2007, the SPP notified OG&E to construct 44 miles of a new 345 kV transmission line which will originate at OG&E's existing Sooner 345 kV substation and proceed generally in a northerly direction to the Oklahoma/Kansas Stateline (referred to as the Sooner-Rose Hill project). At the Oklahoma/Kansas Stateline, the line will connect to the companion line being constructed in Kansas by Westar Energy. Construction of the line is estimated to begin in mid-2011 and the line is estimated to be in service by June 2012.

In January 2009, OG&E received notification from the SPP to begin construction on 50 miles of a new 345 kV transmission line and substation upgrades at OG&E's Sunnyside substation, among other projects. In April 2009, Western Farmers Electric Cooperative assigned to OG&E the construction of 50 miles of line designated by the SPP to be built by Western Farmers Electric Cooperative. The new line will extend from OG&E's Sunnyside substation near Ardmore, Oklahoma, 123.5 miles to the Hugo substation owned by Western Farmers Electric Cooperative near Hugo, Oklahoma. OG&E began preliminary line routing and acquisition of rights-of-way in June 2009. Construction began in January 2011. 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 regional cost allocation mechanism as provided in the SPP tariff for application to such improvements.

On April 28, 2009, the SPP approved the Balanced Portfolio 3E projects. Balanced Portfolio 3E includes four projects to be built by OG&E and includes: (i) construction of 120 miles of transmission line from OG&E's Seminole substation in a northeastern direction to OG&E's Muskogee substation at a cost of $180 million for OG&E, which is expected to be in service by December 2013, (ii) construction of 72 miles of transmission line from OG&E's Woodward District EHV substation in a southwestern direction to the Oklahoma/Texas Stateline to a companion transmission line to be built by Southwestern Public Service to its Tuco substation at a cost of $120 million for OG&E, which is expected to be in service by April 2014, (iii) construction of 38 miles of transmission line from OG&E's Sooner substation in an eastern direction to the Grand River Dam Authority Cleveland substation at an estimated cost of $65 million for OG&E, which is expected to be in service by December 2012 and (iv) construction of a new substation near Anadarko which is expected to consist of a 345/138 kV transformer and substation breakers and will be built in OG&E 7;s portion of the Cimarron-Lawton East Side 345 kV line at an estimated cost of $15 million for OG&E, which is expected to be in service by December 2011. On June 19, 2009, OG&E received a notice to construct the Balanced Portfolio 3E projects from the SPP. On July 23, 2009, OG&E responded to the SPP that OG&E will construct the Balanced Portfolio 3E projects discussed above beginning in early 2011.

On April 27, 2010, the SPP approved, contingent upon approval by the FERC of a regional cost allocation methodology filed with the FERC by the SPP, a set of transmission projects titled "Priority Projects." The Priority Projects consist of several transmission projects, two of which have been assigned to OG&E. The 345 kV projects include: (i) construction of 92 miles of transmission line from OG&E's Woodward District EHV substation to a companion transmission line to be built by Southwestern Public Service to its Hitchland substation in the Texas Panhandle at a cost of $180 million for OG&E, which is expected to be in service by June 2014 and (ii) construction of 80 miles of transmission line from OG&E's Woodward District EHV substation to a companion transmission line at the Kansas border to be built by either Mid-Kansas Electric Company or another company assigned by Mid-Kansas Electric Company at a cost of $135 million to OG&E, which is expected to be in service by December 2014. On June 17, 2010, the FERC approved the cost allocation filed by the SPP and notices to construct these Priority Projects were issued by the SPP on June 30, 2010. On September 27, 2010, OG&E responded to the SPP that OG&E will construct the Priority Projects discussed above beginning in June 2012. The scope of the Woodward District EHV substation/Kansas border Priority Project was subsequently revised and the SPP Board of Directors approved this revision in October 2010. The SPP issued a revised notice to construct for this Priority Project on November 22, 2010. On February 4, 2011, OG&E responded to the SPP that OG&E will construct the revised Priority Project.

The capital expenditures related to the Sooner-Rose Hill, Sunnyside-Hugo, Balanced Portfolio 3E and Priority 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 – Liquidity and Capital Resources – Future Capital Requirements and Financing Activities."

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2009

On October 29, 2010, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2009 fuel adjustment clause. On December 28, 2010, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. A procedural schedule was established in this matter with a hearing scheduled to begin on April 28, 2011.

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. 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. A final settlement was filed with the FERC on August 5, 2010 and an order is pending. With the filing of Enogex's 2009 rate case discussed below, the rate period for th e 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 (i) approving the MEP project including the approval of a limited jurisdiction certificate and (ii) authorizing the Enogex lease agreement with MEP. Accordingly, Enogex proceeded with the construction of facilities necessary to implement this service. On August 2 5, 2008, a 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. On December 28, 2010, the Court of Appeals issued an opinion generally upholding the FERC's orders, but remanding the case for further explanation of one aspect of the FERC's reasoning. The Court of Appeals emphasized that it was not vacating the FERC's orders and that its approval of the Enogex lease agreement with MEP remains in effect and legally binding. On remand, the FERC must clarify that its decision was based on a finding that the lease does not adversely aff ect existing customers on Enogex's system. Enogex anticipates that the FERC will issue an order on remand in the first half of 2011. On January 21, 2011, Apache Corporation filed a motion asking the FERC to establish procedures on remand and to either condition the lease on Enogex's willingness to provide firm Section 311 transportation service to existing customers on all portions of its system or to establish an expedited briefing schedule. On February 7, 2011, Enogex, MEP and Chesapeake Energy Corporation filed a joint answer asking the FERC to find, among other things, that the reduction in the amount of interruptible transportation capacity available due to the MEP lease did not have an adverse affect on Apache Corporation and to acknowledge that Apache Corporation's request to condition the lease on the provision of West Zone 311 firm transportation service has been addressed as Enogex filed a rate case on January 28, 2011 proposing to implement such service effective March 1, 2011.

Enogex FERC Section 311 2009 Rate Case

On March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for its new firm East Zone Section 311 transportation service and to revise the rates for its existing East and West Zone interruptible Section 311 transportation service. In anticipation of offering this new service, Enogex had filed with the FERC, as required by the FERC's regulations, a revised SOC Applicable to Transportation Services to describe the terms, conditions and operating arrangements for the new service. Enogex made the SOC filing on February 27, 2009. Enogex began offering firm East Zone Section 311 transportation service on April 1, 2009. The revised East and West Zone zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for the firm East Zo ne 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. On January 4, 2010, the FERC Staff submitted an offer proposing various adjustments to Enogex's filed cost of service. On April 27, 2010, Enogex submitted comments to the FERC Staff stating that it would agree to the offer, contingent upon all parties agreeing to support or not oppose. Parties have until March 16, 2011 to submit comments stating whether they support, or do not oppose, the FERC Staff's offer.

Enogex Storage SOC Filing

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

Enogex FERC Section 311 2011 Rate Case

On January 28, 2011, Enogex submitted a new rate filing at the FERC to set the maximum rate for a new firm Section 311 transportation service in the West Zone of its system and to revise the currently effective maximum rates for Section 311 interruptible transportation service in the East Zone and West Zone. Along with establishing the rate for a new firm service in the West Zone, Enogex's filing requested a decrease in the maximum interruptible zonal rates in the West Zone and to retain the currently effective rates for firm and interruptible services in the East Zone. Enogex reserved the right to implement the higher rates for firm and interruptible services in the East Zone supported by the cost of service to the extent an expeditious settlement agreement cannot be reached in the proceeding. &# 160;Enogex proposed that the rates be placed into effect on March 1, 2011. Contemporaneous with the rate filing, Enogex submitted a motion to defer the deadline for protests until April 4, 2011 to facilitate expedited settlement negotiations. The regulations provide that the FERC has 150 days to act on the filing but also permit the FERC to issue an order extending the time period for action. No action has yet been taken by the FERC.

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 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 CIP spot check audit. Resolution of any audit findings is expected in early 2011; 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 April 2011, which will incorporate both NERC CIP and non-CIP standards.

State Legislative Initiative

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

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, 2010 and 2009, and the related consolidated statements of income, changes in stockholders' equity, comprehensive income and cash flows for each of the three years in the period ended December 31, 2010. 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, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, 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, 2010, 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, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 17, 2011

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	**2010**	**$ 875.8**	**$ 887.2**	**$ 1,125.4**	**$ 828.5**	**$ 3,716.9**
	2009	$ 606.6	$ 644.1	$ 845.3	$ 773.7	$ 2,869.7
Operating income	**2010**	**$ 86.8**	**$ 151.5**	**$ 274.2**	**$ 81.4**	**$ 593.9**
	2009	$ 52.0	$ 126.4	$ 229.7	$ 83.8	$ 491.9
Net income	**2010**	**$ 25.2**	**$ 77.9**	**$ 163.5**	**$ 33.8**	**$ 300.4**
	2009	$ 17.6	$ 70.9	$ 137.5	$ 35.1	$ 261.1
Net income attributable to OGE Energy	**2010**	**$ 24.2**	**$ 77.3**	**$ 163.1**	**$ 30.7**	**$ 295.3**
	2009	$ 16.8	$ 70.5	$ 136.8	$ 34.2	$ 258.3
Basic earnings per average common share attributable to OGE Energy common shareholders (A)	**2010**	**$ 0.25**	**$ 0.79**	**$ 1.67**	**$ 0.32**	**$ 3.03**
	2009	$ 0.18	$ 0.73	$ 1.42	$ 0.35	$ 2.68
Diluted earnings per average common share attributable to OGE Energy common shareholders (A)	**2010**	**$ 0.25**	**$ 0.78**	**$ 1.65**	**$ 0.31**	**$ 2.99**
	2009	$ 0.18	$ 0.72	$ 1.40	$ 0.35	$ 2.66

(A) Due to the impact of dilution on the EPS calculation, quarterly EPS amounts may not add to the total.

Dividends

COMMON STOCK

- Common quarterly dividends paid (as declared) in 2010 were $0.3625 each for the first three quarters of 2010 and was $0.3750 for the fourth quarter of 2010. 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.
- Present rate – $0.3750
- 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 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 and chief financial officer, 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 chief executive officer and chief fin ancial officer, 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 chief executive officer and chief financial officer 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 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, 2010. 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, 2010, 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 and Chief Executive Officer	Danny P. Harris, 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, 2010, 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 auth orizations 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, 2010, 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, 2010 and 2009, and the related consolidated statements of income, changes in stockholders' equity, comprehensive income and cash flows for each of the three years in the period ended December 31, 2010 of OGE Energy Corp. and our report dated February 17, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 17, 2011

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 chief accounting officer, which is available fo 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, upor 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 postin such information on its web site at the location specified above. The Company will also include in its proxy statement info rmation 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, 2011. Such proxy statement is incorporated herein by reference.

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, 2010, 2009 and 2008

Ÿ Consolidated Statements of Cash Flows for the years ended December 31, 2010, 2009 and 2008

Ÿ Consolidated Balance Sheets at December 31, 2010 and 2009

Ÿ Consolidated Statements of Capitalization at December 31, 2010 and 2009

Ÿ Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2010, 2009 and 2008

Ÿ Consolidated Statements of Comprehensive Income for the years ended December 31, 2010, 2009 and 2008

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	149

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	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)
2.15	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)
2.16	Investment Agreement dated as of October 5, 2010 by and between OGE Energy Corp., Enogex Holdings LLC and Bronco Midstream Holdings, LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed October 6, 2010 (File No. 1-12579) and incorporated by reference herein)
3.01	Copy of Restated OGE Energy Corp. Certificate of Incorporation. (Filed as Exhibit 3.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2010 (File No. 1-12579) and incorporated by reference herein)
3.02	Copy of Amended OGE Energy Corp. By-laws. (Filed as Exhibit 3.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2010 (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. (Filed as Exhibit 4.15 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein)
4.16	Supplemental Indenture No. 11 dated as of June 1, 2010 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed June 8, 2010 (File No. 1-1097) and incorporated by reference herein)
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 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)
10.05	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)
10.06	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)
10.07	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)
10.08*	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)
10.09	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)
10.10	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)
10.11*	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, 2010 (File No. 1-12579) and incorporated by reference herein)
10.12*	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)
10.13	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 10.02 to OGE Energy's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12579) and incorporated by reference herein)
10.14	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 10.03 to OGE Energy's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12579) and incorporated by reference herein)
10.15*	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)
10.16*	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)
10.17	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)
10.18	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)
10.19	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)
10.20	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)
10.21	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 10-Q for the quarter ended September 30, 2010 (File No. 1-12579) and incorporated by reference herein)
10.22*	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)
10.23*	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)
10.24*	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)
10.25*	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)
10.26*	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)
10.27*	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)

10.28*	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)
10.29*	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)
10.30*	Form of Amended and Restated Employment 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)
10.31*	Amended and Restated Employment 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)
10.32*	Form of Employment 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)
10.33*	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)
10.34*	Directors' Compensation.
10.35*	Executive Officer Compensation.
10.36*	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)
10.37*	Employment Agreement 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)
10.38	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)
10.39	Agreement, dated February 17, 2010, between Oklahoma Gas and Electric Company and Oklahoma Department of Environmental Quality. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed February 23, 2010 (File No. 1-12579) and incorporated by reference herein)
10.40*	Amendment No. 1 to the Company's Restoration of Retirement Income Plan. (Filed as Exhibit 10.40 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein)
10.41*	Amendment No. 1 to the Company's Deferred Compensation Plan. (Filed as Exhibit 10.41 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein)
10.42	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 1, 2010 (File No. 1-12579) and incorporated by reference herein)
10.43	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Crossroads application. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed July 1, 2010 (File No. 1-12579) and incorporated by reference herein)
12.01	Calculation of Ratio of Earnings to Fixed Charges.
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)
99.05	Copy of OCC Order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 7, 2010 (File No. 1-12579) and incorporated by reference herein)
99.06	Copy of OCC Order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Crossroads application. (Filed as Exhibit 99.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2010 (File No. 1-12579) and incorporated by reference herein)
99.07	Description of Capital Stock.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.PRE	XBRL Taxonomy Presentation Linkbase Document.
101.LAB	XBRL Taxonomy Label Linkbase Document.
101.CAL	XBRL Taxonomy Calculation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.

* 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, 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
Year Ended December 31, 2010					
Reserve for Uncollectible Accounts	$ 2.4	$ 2.6	$ ---	$ 3.1 (A)	$ 1.9

(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 17th day of February, 2011.

OGE ENERGY CORP.
(Registrant)

By /s/ Peter B. Delaney
Peter B. Delaney
Chairman of the Board 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 17, 2011
/s/ Sean Trauschke Sean Trauschke	Principal Financial Officer; and	February 17, 2011
/s/ Scott Forbes Scott Forbes	Principal Accounting Officer.	February 17, 2011
James H. Brandi	Director;	
Wayne H. Brunetti	Director;	
Luke R. Corbett	Director;	
Kirk Humphreys	Director;	
Robert Kelley	Director;	
Robert O. Lorenz	Director; and	
Leroy C. Richie	Director.	
/s/ Peter B. Delaney By Peter B. Delaney (attorney-in-fact)		February 17, 2011

Exhibit 10.34

OGE ENERGY CORP.
DIRECTORS' COMPENSATION

Compensation of non-officer directors of the Company during 2010 included an annual retainer fee of $107,000, of which $37,500 was payable in cash in monthly installments and $69,500 was deposited in the director's account under the Company's Deferred Compensation Plan in December 2010 and converted to 1,541.703 common stock units based on the closing price of the Company's Common Stock on December 3, 2010. All non-officer directors received $1,500 for each Board meeting and $1,500 for each committee meeting attended. The lead director and the chairman of the Audit Committee received an additional $10,000 cash retainer in 2010. The chairmen of the Compensation and Nominating and Corporate Governance Committees received an additional $5,000 annual cash retainer in 2010. Each chairman of a board committee also received a meeting fee of $1,500 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 2010.

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 day 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 Company's Deferred Compensation Plan. During 2010, those investment options included a Company 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 CompanyR 17;s Deferred Compensation Plan are paid in cash in a lump sum or installments. In certain circumstances, participants may also be entitled to in-service withdrawals from the Company's Deferred Compensation Plan.

In December 2010, the Compensation Committee met to consider director compensation. At that meeting, the Compensation Committee increased the cash portion of the annual retainer for 2011 to $42,000 from $37,500 and increased the annual retainer for 2011 for the lead director from $10,000 to $15,000. The other components of director compensation remained unchanged.

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.

Exhibit 10.35

OGE ENERGY CORP.
EXECUTIVE OFFICER COMPENSATION

Executive Compensation

In December 2010, the Compensation 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 2011. Executive compensation was set by the Compensation Committee after consideration of, among other things, individual performance and market-based data on compensation for executives with similar duties. Payouts of 2011 annual bonus targets and long-term awards are dependent on achievement of specified corporate goals that will be established by the Compensation Committee at a subsequent meeting, and no officer is assured of any payout.

Salary

The Compensation Committee established the base salaries for its senior executive group. The salaries for 2011 for the OGE Energy officers who are expected to be named in the Summary Compensation Table in OGE Energy's 2011 Proxy Statement are as follows:

Executive Officer	2011 Base Salary
Peter B. Delaney, Chairman and Chief Executive Officer	$859,300
Danny P. Harris, President and Chief Operating Officer	$582,000
Sean Trauschke, Vice President and Chief Financial Officer	$440,000
E. Keith Mitchell, Senior Vice President and Chief Operating Officer of Enogex LLC	$337,900
Stephen E. Merrill, Vice President of Human Resources	$263,000

Establishment of 2011 Annual Incentive Awards

As stated above, at its December 2010 meeting, the Compensation 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 2011 corporate goals to be set by the Compensation Committee at a subsequent meeting, to receive from 0 percent to 150 percent of such targeted amount. For 2011, the targeted amount ranged from 50 percent to 90 percent of the approved 2011 base salary for the executive officers in the above table.

Establishment of Long-Term Awards

At its December 2010 meeting, the Compensation 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 Compensation Committee at a subsequent meeting. For 2011, the targeted amount ranged from 85 percent to 240 percent of the approved 2011 base salary for the executive officers in the above table.

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, 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 Compa ny 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 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 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 Code. The 401(k) Plan was amended in October 2009 whereby eligible employees were provided a choice to select a future retirement benefit combination from the Company's Pension Plan and the CompanyR 17;s 401(k) Plan. For those employees who elected to stay in the Pension Plan (prior to it being amended) and 401(k) Plan (prior to it being amended), 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 Dece mber 1, 2009 under the 401(k) Plan (prior to it being amended), 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 not to stay in the Pension Plan (prior to it being amended) and 401(k) Plan (prior to it being amended), effective January 1, 2010, the Company contributes on behalf of each participant, depending on the choice selected, 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 th ree 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 provided to eligible employees 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 2010, those investment fund options included a Company 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 t imes 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. In reviewing the perquisites and the benefits under the SERP, 401(k) Plan, Deferred Compensation Plan, Pension Plan and Restoration of Retirement Income Plan, the Compensation Committee sought in 2010 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 voluntari ly 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 Employment Agreements are filed as Exhibits 10.30, 10.31 10.32 and 10.37 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 and restricted stock 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.

Exhibit 12.01

OGE ENERGY CORP.
RATIO OF EARNINGS TO FIXED CHARGES

Year ended December 31 (*In millions*)	2006	2007	2008	2009	2010
Earnings:					
Pre-tax income from continuing operations	$ 346.6	$ 361.9	$ 338.6	$ 382.2	$ 461.4
Add Fixed Charges	104.1	97.6	130.0	154.5	150.1
Subtotal	450.7	459.5	468.6	536.7	611.5
Subtract:					
Allowance for borrowed funds used during construction	4.5	4.0	4.0	8.3	5.5
Other capitalized interest	0.9	0.9	3.5	6.3	2.5
Total Earnings	445.3	454.6	461.1	522.1	603.5
Fixed Charges:					
Interest on long-term debt	88.3	88.7	106.6	143.6	141.8
Interest on short-term debt and other interest charges	13.1	6.4	21.0	8.5	5.9
Calculated interest on leased property	2.7	2.5	2.4	2.4	2.4
Total Fixed Charges	$ 104.1	$ 97.6	$ 130.0	$ 154.5	$ 150.1
Ratio of Earnings to Fixed Charges	4.28	4.66	3.55	3.38	4.02

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
OGE Enogex Holdings LLC	Oklahoma	100.0
Enogex Holdings LLC	Oklahoma	86.7
Enogex LLC	Oklahoma	86.7
Enogex Gathering & Processing LLC	Oklahoma	86.7
Enogex Products LLC	Oklahoma	86.7
Enogex Gas Gathering LLC	Oklahoma	86.7

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. 333-155756) pertaining to the dividend reinvestment and stock purchase plan and the Registration Statement (Form S-3ASR No. 333-166572) pertaining to common stock and preferred share purchase rights and debt securities, of our rep orts dated February 17, 2011, 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, 2010.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 17, 2011

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, 2010; 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 16th day of February, 2011.

Peter B. Delaney, Chairman, Principal Executive Officer and Director	/s/ Peter B. Delaney
James H. Brandi, Director	/s/ James H. Brandi
Wayne H. Brunetti, Director	/s/ Wayne H. Brunetti
Luke R. Corbett, Director	/s/ Luke R. Corbett
John D. Groendyke, Director	
Kirk Humphreys, Director	/s/ Kirk Humphreys
Robert Kelley, Director	/s/ Robert Kelley
Linda P. Lambert, Director	
Robert O. Lorenz, Director	/s/ Robert O. Lorenz
Leroy C. Richie, Director	/s/ Leroy C. Richie
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, Kelly D. Lang, 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 16th day of February, 2011.

/s/ Kelly D. Lang
Kelly D. Lang
Notary Public in and for the County
of Oklahoma, State of Oklahoma

My Commission Expires:
September 23, 2013

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 17, 2011

/s/ Peter B. Delaney
Peter B. Delaney
Chairman of the Board 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 17, 2011

/s/ Sean Trauschke
Sean Trauschke
Vice President and Chief Financial Officer

Exhibit 32.01

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

In connection with the Annual Report of the Company on Form 10-K for the period ended December 31, 2010, as filed with the SEC (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 17, 2011

/s/ Peter B. Delaney
Peter B. Delaney
Chairman of the Board
and Chief Executive Officer

/s/ Sean Trauschke
Sean Trauschke
Vice President
and Chief Financial Officer

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”, “estimateR 21;, “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 Natural Gas 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 PRM 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 SEC, the FERC, state public utility commissions; the regional state committee which regulates the SPP; 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 EPA, 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 14 of Notes to Consolidated Financial Statements of the Company's Form 10-K for the year ended December 31, 2010, 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 OCC or the APSC;

- Whether OG&E can successfully implement its Smart Grid program to install meters for its customers and integrate the Smart Grid meters with its customer billing and other computer information systems; 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.

DESCRIPTION OF CAPITAL STOCK

The following statements are summaries of certain provisions of our Restated Certificate of Incorporation and are subject to the detailed provisions thereof. Such summaries do not purport to be complete, and reference is made to our Restated Certificate of Incorporation (which is filed as Exhibit 3.01 to our Form 10-Q for the quarter ended June 30, 2010, File No. 1-12579) for a full and complete statement of such provisions.

Authorized Shares

Under our Restated Certificate of Incorporation, we are authorized to issue 125,000,000 shares of common stock, par value $0.01 per share, of which 97,636,311 shares were outstanding on January 31, 2011.

We are also authorized to issue 5,000,000 shares of preferred stock, par value $0.01 per share. No shares of preferred stock are currently outstanding. Without shareholder approval, we may issue preferred stock in the future in such series as may be designated by our board of directors. In creating any such series, our board of directors has the authority to fix the rights and preferences of each series with respect to, among other things, the dividend rate, redemption provisions, liquidation preferences, sinking fund provisions, conversion rights and voting rights. The terms of any series of preferred stock that we may issue in the future may provide the holders of such preferred stock with rights that are senior to the rights of the holders of our common stock.

Dividend Restrictions

Before we can pay any dividends on our common stock, the holders of our 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. Because we are a holding company and conduct all of our operations through our subsidiaries, our cash flow and ability to pay dividends will be dependent on the earnings and cash flows of our subsidiaries and the distribution or other payment of those earnings to us in the form of dividends or distributions, or in the form of repayments of loans or advances to us. We expect to derive principally all of the funds required by us to enable us to pay dividends on our common stock from dividends paid by OG&E, on OG&E's common stock, and from distributions paid by Enogex Holdings, o n OGE Enogex Holding's limited liability company interests. Our 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, the covenants of OG&E's certificate of incorporation and OG&E's debt instruments limiting the ability of OG&E to pay dividends and the ability of public utility commissions that regulate OG&E to effectively restrict the payment of dividends by OG&E. Our ability to receive distributions on OGE Enogex Holding'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 LLC's debt instruments (including Enogex LLC's revolving credit agreement) limiting the ability of Enogex Holdings 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 common stock, premiums on common stock (restricted to premiums on common stock only by SEC 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 currently restricted by these provisions.

Voting Rights

Each holder of common stock is entitled to one vote per share upon all matters upon which shareowners have the right to vote. Our board of directors has the authority to fix conversion and voting rights for any new series of preferred stock (including the right to elect directors upon a failure to pay dividends), provided that no share of preferred stock can have more than one vote per share.

Our Restated Certificate of Incorporation also contains “fair price” provisions, which require the approval by the holders of at least 80 percent of the voting power of our outstanding voting stock as a condition for mergers, consolidations, sales of substantial assets, issuances of capital stock and certain other business combinations and transactions involving us and any substantial (10 percent or more) holder of our voting stock unless the transaction is either approved by a majority of the members of our board of directors who are unaffiliated with the substantial holder or specified minimum price and procedural requirements are met. The provisions summarized in the foregoing sentence may be amended only by the approval of the holders of at least 80 percent of the voting power of our outstanding voting stock . Our voting stock consists of all outstanding shares entitled to vote generally in the election of directors and currently consists of our common stock.

Our voting stock does not have cumulative voting rights for the election of directors. Subject to the possible rights of the holders of preferred stock that may be issued in the future to elect directors under certain circumstances, our Restated Certificate of Incorporation and By-Laws currently contain provisions stating that: (1) directors may be removed only with the approval of the holders of at least a majority of the voting power of our shares generally entitled to vote; (2) any vacancy on the board of directors will be filled only by the remaining directors then in office, though less than a quorum; (3) advance notice of introduction by shareowners of business at annual shareowner meetings and of shareowner nominations for the election of directors must b e given and that certain information must be provided with respect to such matters; (4) shareowner action may be taken only at an annual meeting of shareowners or a special meeting of shareowners called by the President or the board of directors; and (5) the foregoing provisions may be amended only by the approval of the holders of at least 80 percent of the voting power of the shares generally entitled to vote. The Restated Certificate of Incorporation and By-Laws currently contain provisions stating that directors elected at or prior to the annual meeting of shareowners in 2010 will serve three-year terms and be divided into three classes as nearly equal in number as possible with staggered terms of office, but directors elected after the annual meeting of shareowners in 2010 will be elected for one-year terms expiring at the next annual meeting of shareowners. However, recent amendments to Oklahoma corporate law now mandate that large public Oklahoma corporations such as us have a classified board. Under the new law, if a corporation’s certificate of incorporation does not divide the board into classes, the board of directors will be deemed to automatically be divided into three classes consisting of a number of directors as nearly equal in number as possible, with the directors placed sequentially into each class alphabetically by last name. After January 1, 2015, a corporation can elect to opt out of this provision if approved by a majority of the outstanding stock. We are currently evaluating the actions we may take in response to the new law. The foregoing provisions, along with the “fair price” provisions discussed above, the business combination and control share acquisition provision discussed below, may deter attempts to cause a change in control of our company (by proxy contest, tender offer or otherwise) and will make more difficult a change in control that is opposed by our board of directors.

Liquidation Rights

Subject to the possible prior rights of holders of preferred stock that may be issued in the future, in the event of our liquidation, dissolution or winding up, whether voluntary or involuntary, the holders of our common stock are entitled to receive the remaining assets and funds pro rata, according to the number of shares of common stock held.

Other Provisions

Oklahoma has enacted legislation aimed at regulating takeovers of corporations and restricting specified business combinations with interested shareholders. Under the Oklahoma General Corporation Act, a shareowner who acquires more than 15 percent of the outstanding voting shares of a corporation subject to the statute, but less than 85 percent of such shares, is prohibited from engaging in specified “business combinations” with the corporation for three years after the date that the shareowner became an interested stockholder. This provision does not apply if (1) before the acquisition date the corporation’s board of directors has approved either the business combination or the transaction in which the shareowner became an interested shareowner or (2) the corporation’s board of directors approves the business combination and at least two-thirds of the outstanding voting stock of the corporation not owned by the interested shareowner vote to authorize the business combination. The term “business combination” encompasses a wide variety of transactions with or caused by an interested shareowner in which the interested shareowner receives or could receive a benefit on other than a pro rata basis with other shareowners, including mergers, specified asset sales, specified issuances of additional shares to the interested shareowner, transactions with the corporation that increase the proportionate interest of the interested shareowner or transactions in which the interested shareowner receives certain other benefits.

Oklahoma law also contains control share acquisition provisions. These provisions generally require the approval of the holders of a majority of the corporation’s voting shares held by disinterested shareowners before a person purchasing one-fifth or more of the corporation’s voting shares can vote the shares in excess of the one-fifth interest. Similar shareholder approvals are required at one-third and majority thresholds.

The board of directors may allot and issue shares of common stock for such consideration, not less than the par value thereof, as it may from time to time determine. No holder of common stock has the preemptive right to subscribe for or purchase any part of any new or additional issue of stock or securities convertible into stock. Our common stock is not subject to further calls or to assessment by us.

Our common stock is listed on the New York Stock Exchange. BNY Mellon Shareowner Services is the Transfer Agent and Registrar for our common stock.