

OGE ENERGY CORP.
Form 10-K
February 17, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

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

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

Commission File Number: 1-12579

OGE ENERGY CORP.

(Exact name of registrant as specified in its charter)

Oklahoma
(State or other jurisdiction of
incorporation or organization)

73-1481638
(I.R.S. Employer
Identification No.)

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

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 No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.

Yes No

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 No

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). Yes No

OGE ENERGY CORP.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2010

TABLE OF CONTENTS

	Page
<u>GLOSSARY OF TERMS</u>	ii
<u>FORWARD-LOOKING STATEMENTS</u>	1
<u>Part I</u>	
<u>Item 1.</u> Business	2
<u>The Company</u>	2
<u>Electric</u> Operations – OG&E	3
<u>Natural</u> Gas Midstream Operations – Enogex	11
<u>Environmental</u> Matters	20
<u>Finance</u> and Construction	21
<u>Employees</u>	24
<u>Executive</u> Officers	24
<u>Access</u> to SEC Filings	26
<u>Item 1A.</u> Risk Factors	26
<u>Item 1B.</u> Unresolved Staff Comments	37
<u>Item 2.</u> Properties	38
<u>Item 3.</u> Legal Proceedings	40
<u>Item 4.</u> [Removed and Reserved]	41
<u>Part II</u>	
<u>Item 5.</u> Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	42
<u>Item 6.</u> Selected Financial Data	44
<u>Item 7.</u> Management’s Discussion and Analysis of Financial Condition and Results of Operations	45
<u>Item 7A.</u> Quantitative and Qualitative Disclosures About Market Risk	79
<u>Item 8.</u> Financial Statements and Supplementary Data	81
	139

Item 9. Changes In and Disagreements with Accountants on Accounting and Financial Disclosure

Item 9A. Controls and Procedures 139

Item 9B. Other Information 142

Part III

Item 10. Directors, Executive Officers and Corporate Governance 142

Item 11. Executive Compensation 142

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters 142

Item 13. Certain Relationships and Related Transactions, and Director Independence 142

Item 14. Principal Accounting Fees and Services 142

Part IV

Item 15. Exhibits, Financial Statement Schedules 142

Signatures 150

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

ii

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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
SO ₂	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
Windspeed

Value-at-risk
OG&E's transmission line from Oklahoma City, Oklahoma to
Woodward, Oklahoma

iii

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 risk factors discussed in “Item 1A. Risk Factors” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” herein, factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- general economic conditions, including the availability of credit, access to existing lines of credit, 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 holds 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 interest 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 operating 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:

Year ended December 31	2010	2010 vs. 2009		2009 vs. 2008	
		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

4

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 for 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 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'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.

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 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 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 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 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 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 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'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 available 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 of these fuel costs that is not included in the base rates is recoverable through OG&E's fuel adjustment clauses that are approved by the OCC, the APSC and the FERC.

Coal

All of OG&E's coal-fired units, with an aggregate capability of 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 Clean 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 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 constitutes less than 50 percent of the total fair market value of the assets involved in the transaction. A member permitted to pursue a transaction independently pursuant to the foregoing is not required to offer the assets associated with such transaction to Enogex Holdings.

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 contracts, the shipper also pays a transportation or commodity charge with respect to quantities actually transported by Enogex. Enogex's obligation to provide interruptible transportation service means that it is obligated to transport natural gas nominated by the shipper only to the extent that it has available capacity. For this service, the shipper pays no demand or reservation charge but pays a transportation or commodity charge for quantities actually shipped. Enogex derives a substantial portion of its transportation revenues from firm transportation services and leased capacity. To the extent pipeline capacity is not needed for such firm transportation services and leased capacity, Enogex offers interruptible interstate transportation services pursuant to Section 311 of the NGPA as well as interruptible intrastate transportation services.

Enogex delivers natural gas to most interstate and intrastate pipelines and end-users connected to its systems from the Arkoma and Anadarko basins (including recent growth activity in the Granite Wash play, 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, Quest 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 provided 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 from 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 ability to efficiently provide varying levels of electric generation relative to other forms of generation, a key part of their effectiveness is contingent upon having access to an integrated pipeline and storage system that can respond quickly to meet their corresponding fluctuating fuel needs. We believe that Enogex is well positioned to compete for the needs of these generators due to the ability of its transportation and storage assets to provide no-notice load following service.

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

Regulation

The transportation rates charged by Enogex for transporting natural gas in interstate commerce are subject to the jurisdiction of the FERC under Section 311 of the NGPA. Rates to provide such service must be "fair and equitable" under the NGPA and are subject to review and approval by the FERC at least once every 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. 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 Zone Section 311 transportation service and the increase in the rates for East and West Zone and interruptible Section 311 service are being collected, subject to refund, pending the FERC approval of the proposed rates. A number of parties intervened in both the rate case and the SOC filing and some additionally filed protests. 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 true-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, Enogex cannot predict the ultimate costs of its integrity management program and compliance with this regulation because those costs will depend on the number and extent of any repairs found to be necessary. Enogex will continue to assess, remediate and maintain the integrity of its pipelines. The results of these activities could cause Enogex to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

Recent System Expansions

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

In December 2006, Enogex entered into a firm capacity lease agreement with MEP for a primary term of 10 years (subject to possible extension) that gives MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP lease agreement is currently 272 MMcf/d, with the quantity ultimately to be leased subject to being increased by mutual agreement pursuant to the lease agreement. In addition to MEP's lease of Enogex's capacity, the MEP project included construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. In support of the MEP lease agreement, Enogex constructed 43 miles of 24-inch steel pipe in Woods and Major counties in Oklahoma, and added 24,000 horsepower of electric-driven compression in Bennington, Oklahoma. Enogex's capital expenditures allocated to its support of the MEP lease agreement were \$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 gathering systems and are delivered to processing plants for the extraction of NGLs, leaving residual dry gas that meets transmission pipeline and commercial quality specifications. Enogex is active

in the extraction and marketing of NGLs from natural gas. The liquids extracted include condensate liquids, marketable ethane, propane, butanes and natural gasoline mix. The residue gas remaining after the liquid products have been extracted consists primarily of ethane and methane.

Enogex's gathering system includes 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 sale 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 otherwise 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 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.

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 Midstream Partners, L.P., Crosstex Energy LP, DCP Midstream Partners, LP, Enbridge Energy Partners, L.P., Hiland Partners, MarkWest Energy Partners, L.P. and Oneok Partners, L.P. In processing and marketing NGLs, Enogex competes against virtually all other gas processors extracting and selling NGLs in its market area.

Regulation

State regulation of natural gas gathering facilities generally includes various safety, environmental and nondiscriminatory rate and open access requirements and complaint-based rate regulation. Enogex may be subject to state common carrier, ratable take and common purchaser statutes. The common carrier and ratable take statutes generally require gatherers to carry, transport and deliver, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers that

purchase gas to purchase without undue discrimination as to source of supply or producer. These statutes may have the effect of restricting Enogex's right to decide with whom it contracts to purchase natural gas or, as an owner of gathering facilities, to decide with whom it contracts to purchase or gather natural gas.

Oklahoma and Texas have each adopted a form of complaint-based regulation of gathering operations that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering open access and rate discrimination. Texas has also adopted a complaint based regulation, 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. Enogex 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 administered by the Texas Railroad Commission. Enogex's natural gas pipelines have inspection and audit programs designed to maintain compliance with pipeline safety and pollution control requirements.

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

Marketing

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 counterparties 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 impingement 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 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. 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. McQuiston	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.

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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. McQuiston 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.

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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	<p>2010 – Present: Chairman of the Board and Chief Executive Officer of OGE Energy Corp. and OG&E</p> <p>2010 – Present: Chief Executive Officer of Enogex Holdings</p> <p>2006 – Present: Chief Executive Officer of Enogex LLC</p> <p>2007 – 2010: Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp. and OG&E</p> <p>2007: President and Chief Operating Officer of OGE Energy Corp. and OG&E</p> <p>2006 – 2007: Executive Vice President and Chief Operating Officer of OGE Energy Corp. and OG&E</p>
Danny P. Harris	<p>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</p> <p>2007 – 2010: Senior Vice President and Chief Operating Officer of OGE Energy Corp. and OG&E and President of Enogex LLC</p> <p>2006 – 2007: Senior Vice President of OGE Energy Corp. and President and Chief Operating Officer of Enogex Inc.</p>
Sean Trauschke	<p>2009 – Present: Vice President and Chief Financial Officer of OGE Energy Corp. and OG&E</p> <p>2010 – Present: Chief Financial Officer of Enogex Holdings</p> <p>2009 – Present: Chief Financial Officer of Enogex LLC</p> <p>2007 – 2009: Senior Vice President – Investor Relations and Financial Planning of Duke Energy</p> <p>2006 – 2007: Vice President – Investor Relations of Duke Energy</p> <p>2006: Vice President and Chief Risk Officer of Duke Energy (electric utility)</p>
Patricia D. Horn	<p>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</p> <p>2006 – 2010: Vice President – Legal, Regulatory and Environmental Health & Safety, General Counsel and Secretary of Enogex LLC</p> <p>2006 – 2010: Assistant General Counsel of OGE Energy Corp.</p>
Gary D. Huneryager	<p>2006 – Present: Vice President – Internal Audits of OGE Energy Corp. and OG&E</p>
S. Craig Johnston	<p>2007 – Present:</p>

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	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. McQuiston	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)

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Name	Business Experience
Stephen E. Merrill	<p>2009 – Present: Vice President – Human Resources of OGE Energy Corp. and OG&E</p> <p>2007 – 2009: Vice President and Chief Financial Officer of Enogex LLC</p> <p>2006 – 2007: Vice President and Chief Financial Officer of Cayenne Drilling, LLC and Sunstone Energy Group LLC (oil and gas company)</p> <p>2006: Director of U.S. Operations at Plains All-American Pipeline L.P. (crude oil transportation and storage company)</p>
E. Keith Mitchell	<p>2007 – Present: Senior Vice President and Chief Operating Officer of Enogex LLC</p> <p>2007: Senior Vice President of Enogex Inc.</p> <p>2006 – 2007: Vice President – Transportation Services of Enogex Inc.</p>
Howard W. Motley	<p>2006 – Present: Vice President – Regulatory Affairs of OG&E</p> <p>2006: Director – Regulatory Affairs and Strategy of OG&E</p>
Reid V. Nuttall	<p>2009 – Present: Vice President – Chief Information Officer of OGE Energy Corp. and OG&E</p> <p>2006 – 2009: Vice President – Enterprise Information and Performance of OGE Energy Corp. and OG&E</p> <p>2006: Vice President – Enterprise Architecture of National Oilwell Varco (oil and gas equipment company)</p>
Melvin H. Perkins, Jr.	<p>2007 – Present: Vice President – Power Delivery of OG&E</p> <p>2006 – 2007: Vice President – Transmission of OG&E</p>
Paul L. Renfrow	<p>2006 – Present: Vice President – Public Affairs of OGE Energy Corp. and OG&E</p>
William J. Bullard	<p>2010 – Present: General Counsel of OG&E and Assistant General Counsel of OGE Energy Corp.</p> <p>2006 – 2010: Assistant General Counsel of OGE Energy Corp. and OG&E</p>
Scott Forbes	<p>2006 – Present: Controller and Chief Accounting Officer of OGE Energy Corp. and OG&E</p> <p>2008 – 2009: Interim Chief Financial Officer of OGE Energy Corp. and OG&E</p>
Max J. Myers	<p>2009 – Present: Treasurer of OGE Energy Corp. and OG&E</p> <p>2010 – Present: Treasurer of Enogex Holdings</p> <p>2008:</p>

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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's electric generating facilities could be required, which may result in significant capital and operating expenditures.

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

There also is growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation 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 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 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 with our planned extensive investment. This could adversely affect our results of operations and financial position. While we may seek to limit the impact of any denied recovery by attempting to reduce the scope of our capital investment, there can no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

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 are numerous uncertainties inherent in estimating future production. As a result, new facilities may not be able to attract sufficient throughput to achieve expected investment return, which could adversely affect Enogex's results of operations, consolidated financial position and cash flows. In addition, the construction of additions to existing gathering and transportation assets may require new rights-of-way prior to construction. Those rights-of-way to connect new natural gas supplies to existing gathering lines may be unavailable and Enogex may not be able to capitalize on attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, Enogex's consolidated financial position, results of operations and cash flows could be adversely affected.

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 allocated to

individual customers. OG&E records the hourly sales to the SPP at market rates in Operating Revenues and the hourly purchases from the SPP at market rates in Cost of Goods Sold in its Consolidated Financial Statements. OG&E's revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operation and regulation by the FERC or the SPP 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 special 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 pipeline rates and rules and policies that may indirectly affect the intrastate natural gas transportation business.

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

The FERC has jurisdiction over transportation rates charged by Enogex for transporting natural gas in interstate commerce under Section 311 of the NGPA. Rates to provide such service must be "fair and equitable" under the NGPA and are subject to review and approval by the FERC at least once every three years. See Note 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 what effect, if any, such changes might have on Enogex's operations, but Enogex could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect Enogex's business. Any such state regulation could have an adverse impact on Enogex's business and its consolidated financial position, results of operations or cash flows.

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

Pursuant to the 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 these activities could cause Enogex to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

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

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

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

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

The Energy Policy Act of 2005 gave the FERC authority to establish mandatory electric reliability rules enforceable with significant monetary penalties. The FERC has approved the NERC as the Electric Reliability Organization for North America and delegated to it the development and enforcement of electric transmission reliability rules. It is the Company's intent to comply with

all applicable reliability rules and expediently correct a violation should it occur. OG&E is subject to a NERC compliance audit every three years as well as periodic spot check audits and cannot predict the outcome of those audits.

OPERATIONAL RISKS

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

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

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 types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than existing insurance coverage.

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

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

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

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

Natural gas and NGLs prices are volatile, and changes in these prices could negatively affect Enogex's 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 and 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 compensation 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 Enogex is not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells, throughput on its gathering, processing and transportation facilities would decline, which could have a material adverse effect on its business, results of operations and cash flows.

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

All of Enogex's businesses are dependent on the continued availability of natural gas production. Enogex does not have control over the level of drilling activity in the areas of its operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. The primary factor that impacts drilling decisions is natural gas prices. Natural gas prices reached relatively high levels in mid-2008 due to the impact of rising demand for natural gas but have returned to the near \$4.00 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 these assets. Other factors that impact production decisions include producers' capital budgets, access to credit, the ability of producers to obtain necessary drilling and other governmental permits, costs of steel and other commodities, geological considerations, demand for hydrocarbons, the level of reserves, other production and development costs and regulatory changes. Because of these factors, even if new natural gas reserves are discovered in areas served by Enogex's assets, producers may choose not to develop those reserves.

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

The Company is exposed to changes in commodity prices in its operations. To minimize the risk of commodity prices, the Company may enter into physical forward sales or financial derivative contracts to hedge purchase and sale commitments, fuel requirements, contractual long/short obligations, keep-whole positions, 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 Enogex's hedging activities, these activities can result in substantial losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect or ineffective, or the hedging policies and procedures are not followed or do not work as planned.

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

Enogex relies on certain key natural gas producer customers for a significant portion of its natural gas and NGLs supply. During 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. Enogex's current contract with PSO expires January 1, 2013, unless extended. The stated term of Enogex's current contract with OG&E expired April 30, 2009, but the contract will remain in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 180 days prior to the commencement of the next succeeding annual period. Because neither party provided notice of termination 180 days prior to May 1, 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 of its competitors and customers. All of these competitive pressures could have a material adverse effect on Enogex's consolidated financial position, results of operations and cash flows.

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

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

• damage to pipelines and plants, related equipment and surrounding properties caused by tornadoes, floods, earthquakes, fires and other natural disasters and acts of terrorism;

• inadvertent damage from third parties, including construction, farm and utility equipment;

• leaks of natural gas, NGLs and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities; and

• fires and explosions.

These and other risks could result in substantial losses due to personal injury and loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of Enogex's related operations. Enogex's insurance is currently provided under the Company's insurance programs. Enogex is not fully insured against all risks inherent to its business. Enogex is not insured against all environmental accidents that might occur, which may include toxic tort claims. In addition, Enogex may not be able to maintain or obtain insurance of the type and amount desired at reasonable rates. Moreover, in some instances, significant claims by the Company may limit or eliminate the amount of insurance

proceeds available to Enogex. As a result of market conditions, premiums and deductibles for certain of the Company's insurance policies have increased substantially, and could escalate further. In some instances, insurance could become unavailable or available only for reduced amounts of coverage. If a significant accident or event occurs that is not fully insured, it could adversely affect Enogex's operations and financial results.

FINANCIAL RISKS

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

We have a 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 significant impact on our results of operations and consolidated financial position. Those factors are outside of our control.

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

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

Workforce demographic issues challenge employers nationwide and are of particular concern to the electric utility and natural gas pipeline industry. The median age of utility and natural gas pipeline workers is significantly higher than the national average. Over the next three years, 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 contractual restrictions that may be applicable to such subsidiary, which may include requirements to maintain minimum levels of working capital and other assets. Claims of creditors, including general creditors, of our subsidiaries on the assets of these subsidiaries will have priority over our claims generally (except to the extent that we may be a creditor of the subsidiaries and our claims are recognized) and claims by our shareowners.

In addition, as discussed above, OG&E is regulated by state utility commissions in Oklahoma and Arkansas 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.

37

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	
Sooner	3	1975	Steam-Turbine	Gas/Oil	Base Load	25.0%	502	1,504
	1	1979	Steam-Turbine	Coal	Base Load	78.2%	522	
	2	1980	Steam-Turbine	Coal	Base Load	50.5%	524	1,046
Horseshoe Lake	6	1958	Steam-Turbine	Gas/Oil	Base Load	19.9%	159	
	7	1963	Combined Cycle	Gas/Oil	Base Load	32.6%	227	
	8	1969	Steam-Turbine	Gas	Base Load	17.5%	380	
Mustang	9	2000	Combustion-Turbine	Gas	Peaking	1.6% (C)	46	
	10	2000	Combustion-Turbine	Gas	Peaking	6.9% (C)	46	858
	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
	1	2003	Combined Cycle	Gas	Base Load	44.6%	149	
Redbud (D)	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 upon which the assets are located, and Enogex believes that it has satisfactory leasehold estates to such lands. Enogex has no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by Enogex or to its title to any material lease, easement, right-of-way, permit or lease, and Enogex believes that it has satisfactory title to all of its material leases, easements, rights-of-way, permits and licenses.

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

At December 31, 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

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

1. **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 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.

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 on 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, asking the court to proceed with the original class action. On July 8, 2010, a hearing in this matter was held and the court granted the plaintiffs motion to lift the stay of discovery previously imposed by the Oklahoma Supreme Court but denied any other specific relief pending further action by the court. On August 4, 2010, OG&E filed an application to assume original jurisdiction and a petition for a writ of prohibition with the Oklahoma Supreme

Court. On September 13, 2010, the Oklahoma Supreme Court issued a writ prohibiting the District Court judge from proceeding further in this case except to dismiss the case. On September 20, 2010, the plaintiffs filed a motion to reconsider this matter with the Oklahoma Supreme Court. 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.

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.

2011	Dividend Paid	High	Price Low
First Quarter (through January 31)	\$ 0.3750	\$ 46.60	\$ 44.69
2010	Dividend Paid	High	Price 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
2009	Dividend Paid	High	Price 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 pay 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) 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.

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)

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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

44

(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 discussion 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 Holdings. 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 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 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 drilling activity near these systems, Enogex's ability to compete for volumes from successful new wells and Enogex's ability to expand capacity as needed.

Enogex'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 development is changing the mix of the potential sources of new generation in the region. Adoption of renewable portfolio standards would be expected to increase the region's reliance on wind generation 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. 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. 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. Enogex 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

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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 power 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:

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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:

- 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;
- 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;
 - revenues from the Arkansas rate increase, which increased the gross margin by \$9.3 million;
 - new customer growth in OG&E's service territory, which increased the gross margin by \$8.1 million; and
- increased transmission revenues due to higher transmission volumes and increased rates due to the FERC formula rate tariff filing, which increased the gross margin by \$1.8 million.

These increases in the gross margin were partially offset by:

- milder weather in OG&E's service territory, which decreased the gross margin by \$18.2 million; and
- lower demand and related revenues by non-residential customers in OG&E's service territory, which decreased the gross margin by \$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:

- 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;
- 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;
- an increase in capitalized labor in 2009 as compared to 2008, which decreased other operation and maintenance expenses by \$7.7 million;
 - a decrease of \$3.8 million in fleet transportation expense primarily due to lower fuel costs in 2009; and
- 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:

- 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;
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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;

 • an increase of \$5.4 million in pension expense;

• an increase of \$3.3 million due to OG&E's demand-side management initiatives, which expenses are being recovered through a rider;

 • an increase of \$2.2 million in medical and dental expenses; and

 • 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

Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
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Year Ended December 31,
2010

(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

56

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Year Ended December 31, 2009 (In millions)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
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 (In millions)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
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 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.

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;

• increased fixed processing fees of \$13.8 million; and
• 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:

• 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
• 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:

• 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
• 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:

• 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;
• 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
• 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:

• 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
• 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 natural 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 compressor station. In the normal course of Enogex's business, the operation of its gathering, processing and transportation assets results in the creation of physical natural gas long/short positions. These physical positions can result from gas imbalances, actual versus contractual settlement differences, fuel tracker obligations and natural gas received in-kind for compensation or reimbursements. Enogex actively manages its monthly net position through either selling excess gas or purchasing additional gas needs from third parties 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;

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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 resulted 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
Y 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 isolation or as a substitute for analysis of the Company's results as reported under GAAP. Because these non-GAAP financial measures exclude some, but not all, items that affect net income and EPS and are defined differently by different companies in the Company's industry, the Company's definition of Ongoing Earnings and Ongoing EPS may not be comparable to a similarly titled measure of other companies.

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

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

	2010		2010	2009	2008
(In millions)	Ongoing Earnings (Loss)	Medicare Part D Tax Subsidy	GAAP Net Income (Loss)	GAAP and Ongoing Net Income (Loss) (A)	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

	2010		2010	2009	2008
(In millions)	Ongoing EPS	Medicare Part D Tax Subsidy	GAAP EPS	GAAP and Ongoing EPS (B)	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 maximum 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 reimbursement 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.

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(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	
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.

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(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.

December 31 (In millions)	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
	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 financial 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 effect 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 impact 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. 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 Accounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income.

Enogex recognizes revenue from natural gas gathering, processing, transportation, 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 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.

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 factors such as pricing relationships between various energy commodities and geographic location. Actual experience can vary significantly from these estimates and assumptions.

In nearly all cases, independent market prices are obtained and compared to the values used in determining the fair value, and an oversight group outside of the marketing organization monitors all modeling methodologies and assumptions. The recorded value of the energy contracts may change significantly in the future as the market price for the commodity changes, but the value of transactions not designated as cash flow hedges is subject to mark-to-market risk loss limitations provided under the Company's risk policies. Management utilizes models to estimate the fair value of the Company's energy contracts including derivatives that do not have an independent market price. At December 31, 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

75

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 the 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 NO_x regulations of the acid rain program, OG&E committed to meeting a 0.45 lbs/MMBtu NO_x 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 NO_x emission level of 0.40 lbs/MMBtu for these boilers which began in 2008. OG&E's average NO_x 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 final 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 mitigation 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	Total	12/31/10 Fair Value
Fixed-rate debt (A)								
Principal amount	\$ ---	\$ ---	\$ ---	\$ 300.0	\$ ---	\$ 1,910.0	\$ 2,210.0	\$ 2,418.6
Weighted-average interest rate	---	---	---	6.25 %	---	6.48%	6.44%	---
Variable-rate debt (B)								
Principal amount	---	---	25.0	---	---	\$ 135.4	\$ 160.4	\$ 160.4
Weighted-average interest rate	---	---	0.57 %	---	---	0.49%	0.50%	---

(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 operating income. Because the commodities covered by these hedges are substantially the same commodities that the Company buys and sells in the physical market, no special studies other

than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

A sensitivity analysis has been prepared to estimate the Company's exposure to the 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. 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	\$1,109.9	\$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)

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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