10011336

OG+E

2009 Annual Report

SEC Mail Processing Section
APR 01 2010
Washington, DC
112

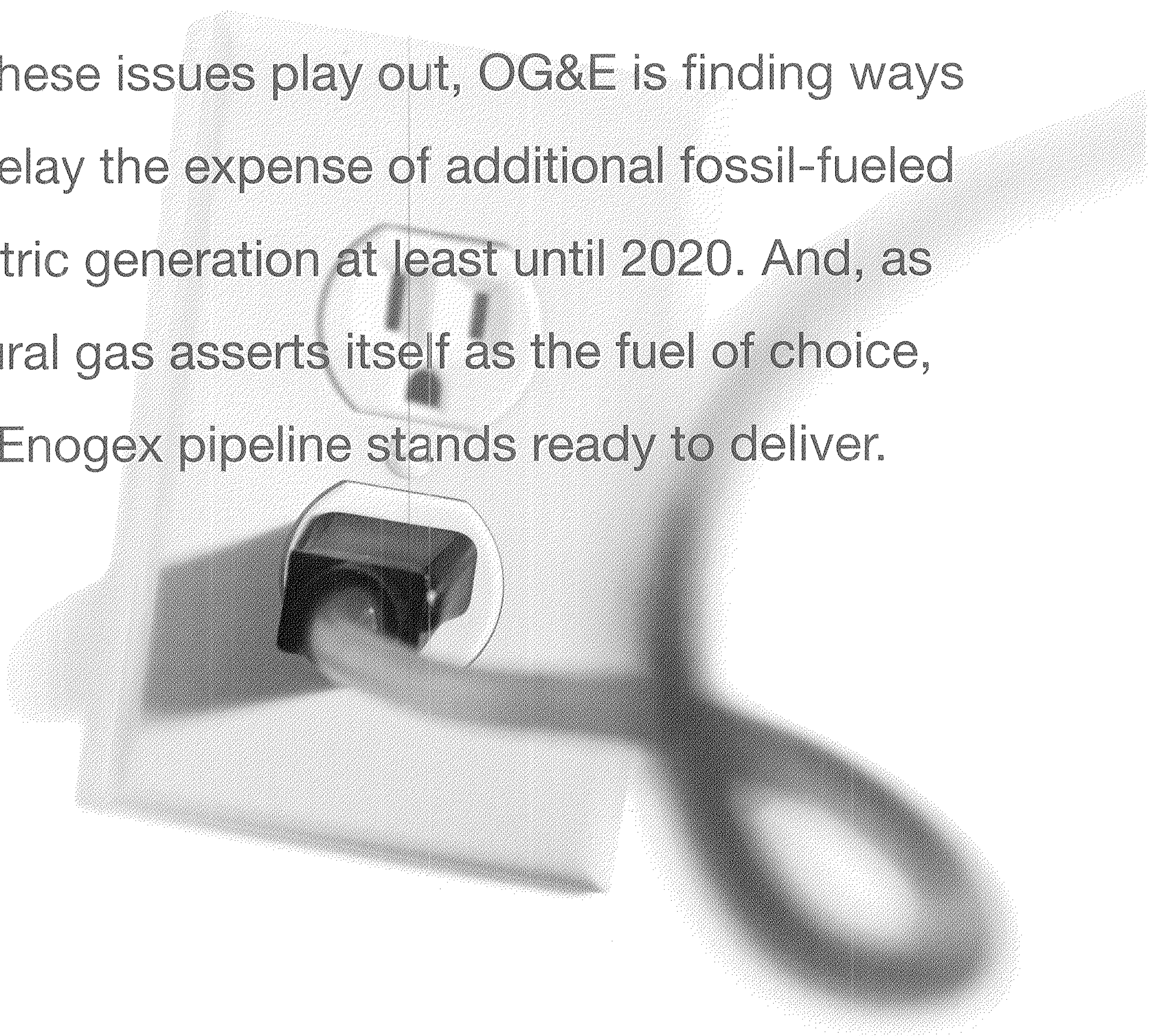
next generation

The world is changing.

But we're not waiting around to see what happens. We're executing our plans today, focused clearly on the landscape ahead.

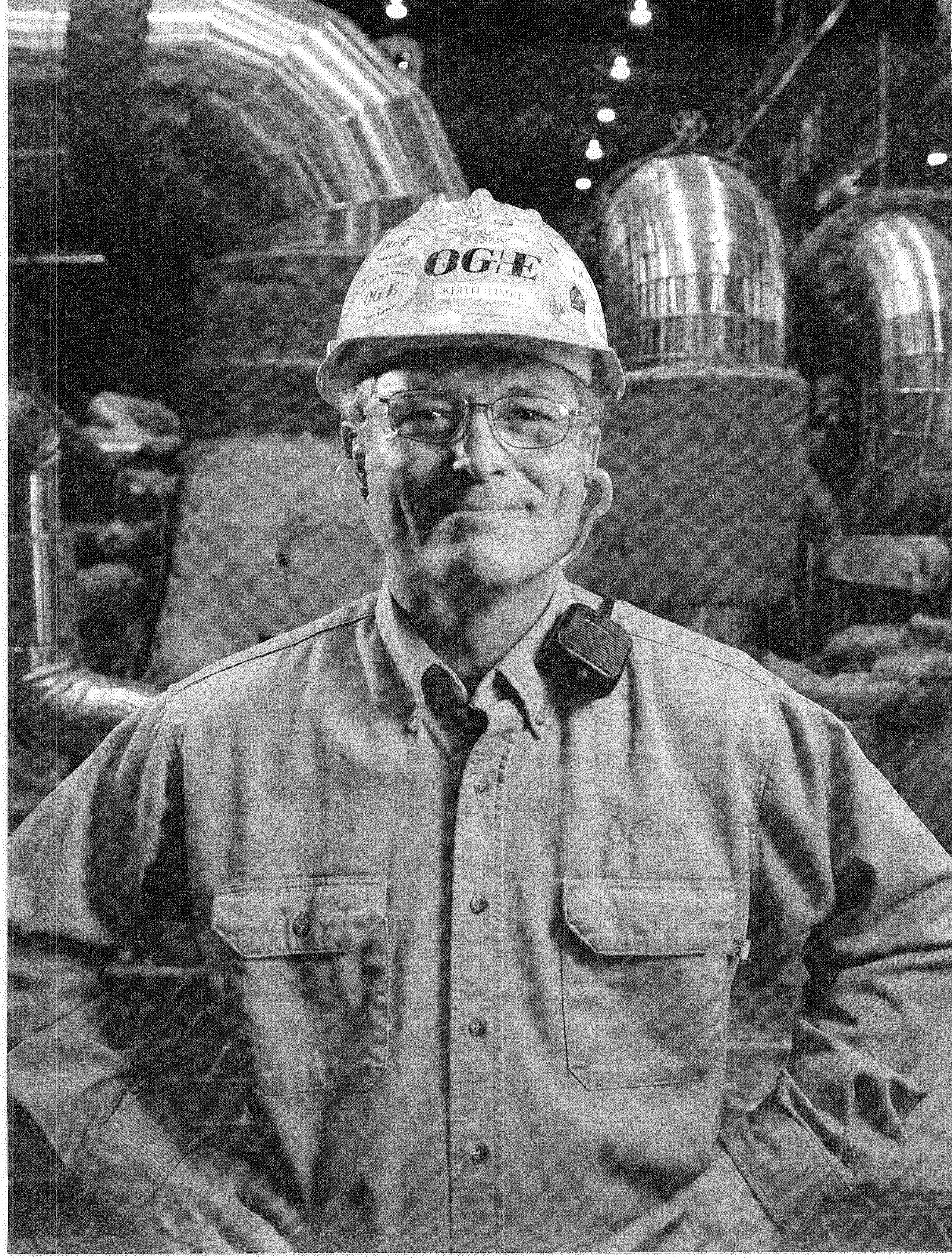
Environmental concerns are driving new energy policies, and demand for renewable energy grows as new technologies redefine the possible.

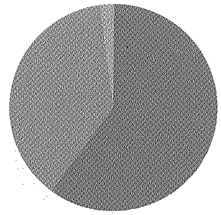
As these issues play out, OG&E is finding ways to delay the expense of additional fossil-fueled electric generation at least until 2020. And, as natural gas asserts itself as the fuel of choice, our Enogex pipeline stands ready to deliver.



generation

The next generation will demand solutions that protect the environment, control costs and supply the energy required to drive the modern economy.


OG+E



2009 Generation by Source

- Coal 60%
- Natural Gas 38%
- Wind 2%

+8%

2009 increase in natural gas' share of OGE's generation mix from 2008

We have a strong commitment to renewable energy. In fact, we're in the midst of a five-year effort to quadruple our wind generation capacity. The near-term goal of 770 megawatts would push OG&E's wind capability to more than 10 percent of total generating capacity.

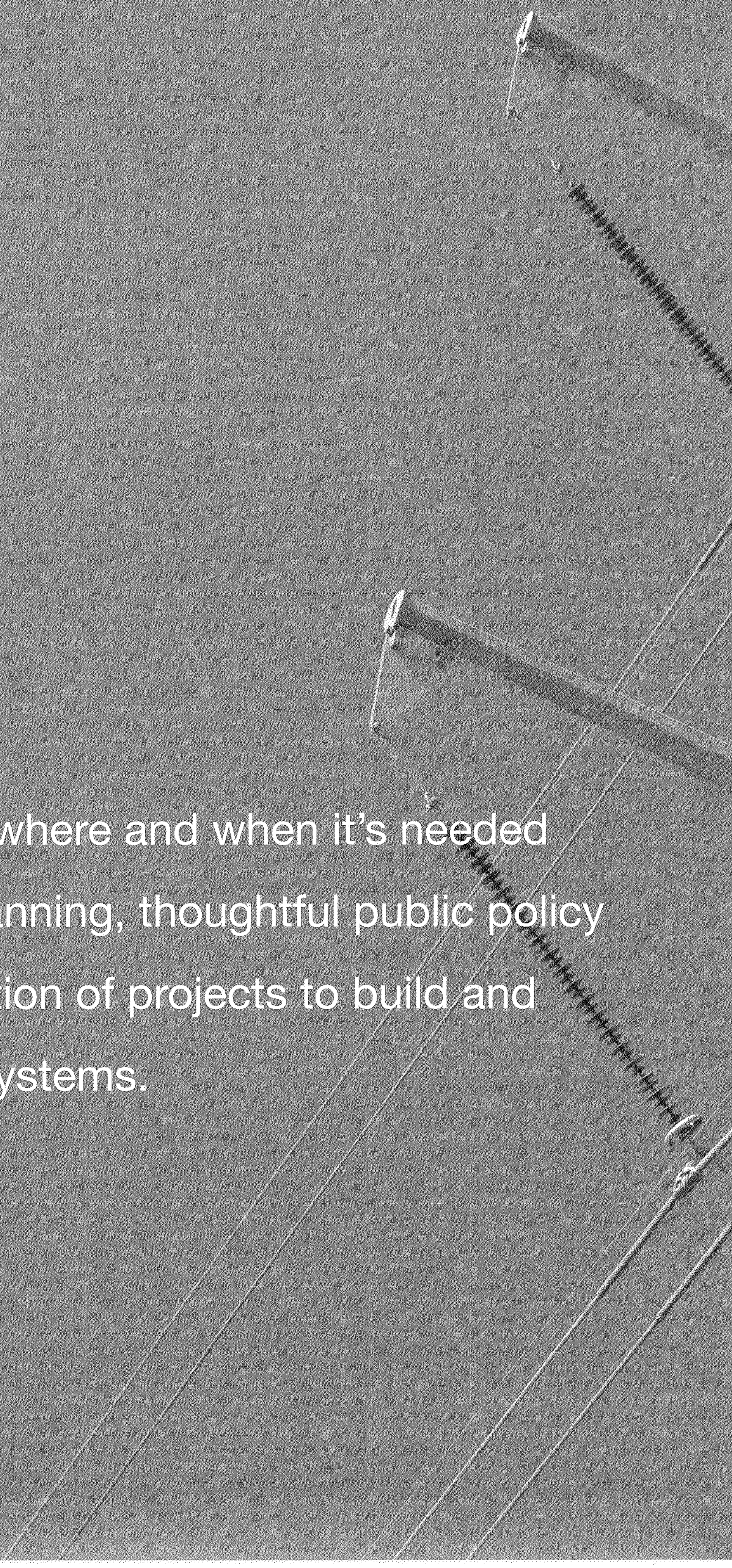
But, there is more to our strategy. Another key to reaching our 2020 goal is ensuring the efficiency and long life of our existing power plants, which today provide 98 percent of the electricity our customers use. The economy runs on electricity and demand continues to grow; so we are going to need all of our base load power plants for many years to come.

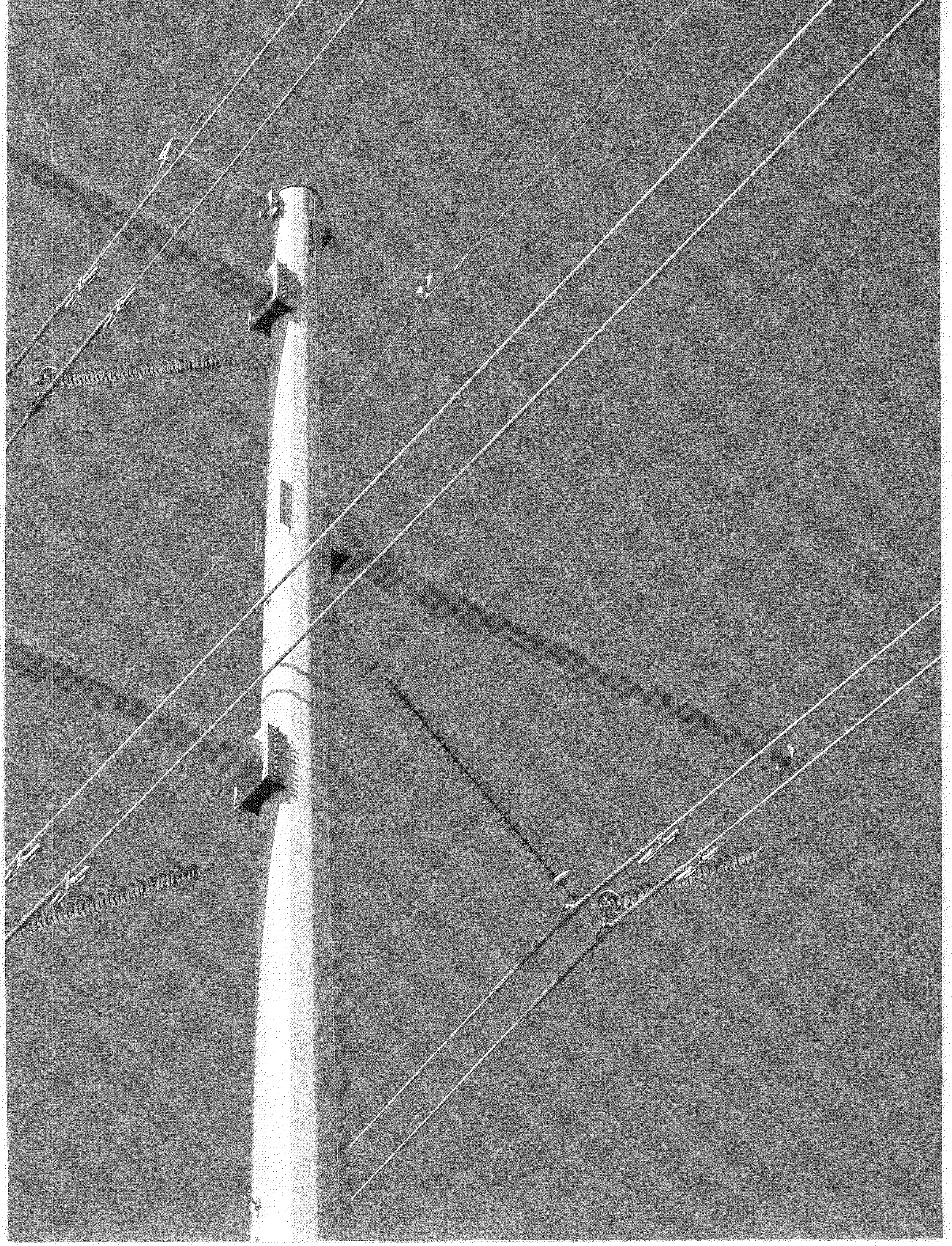
At the same time, our Enogex pipeline system is ideally positioned to support our nation's increasing demand for natural gas, serving producers at the wellhead and processing plant, and then delivering to large consumers including electric power plants, gas utilities and industrial customers.

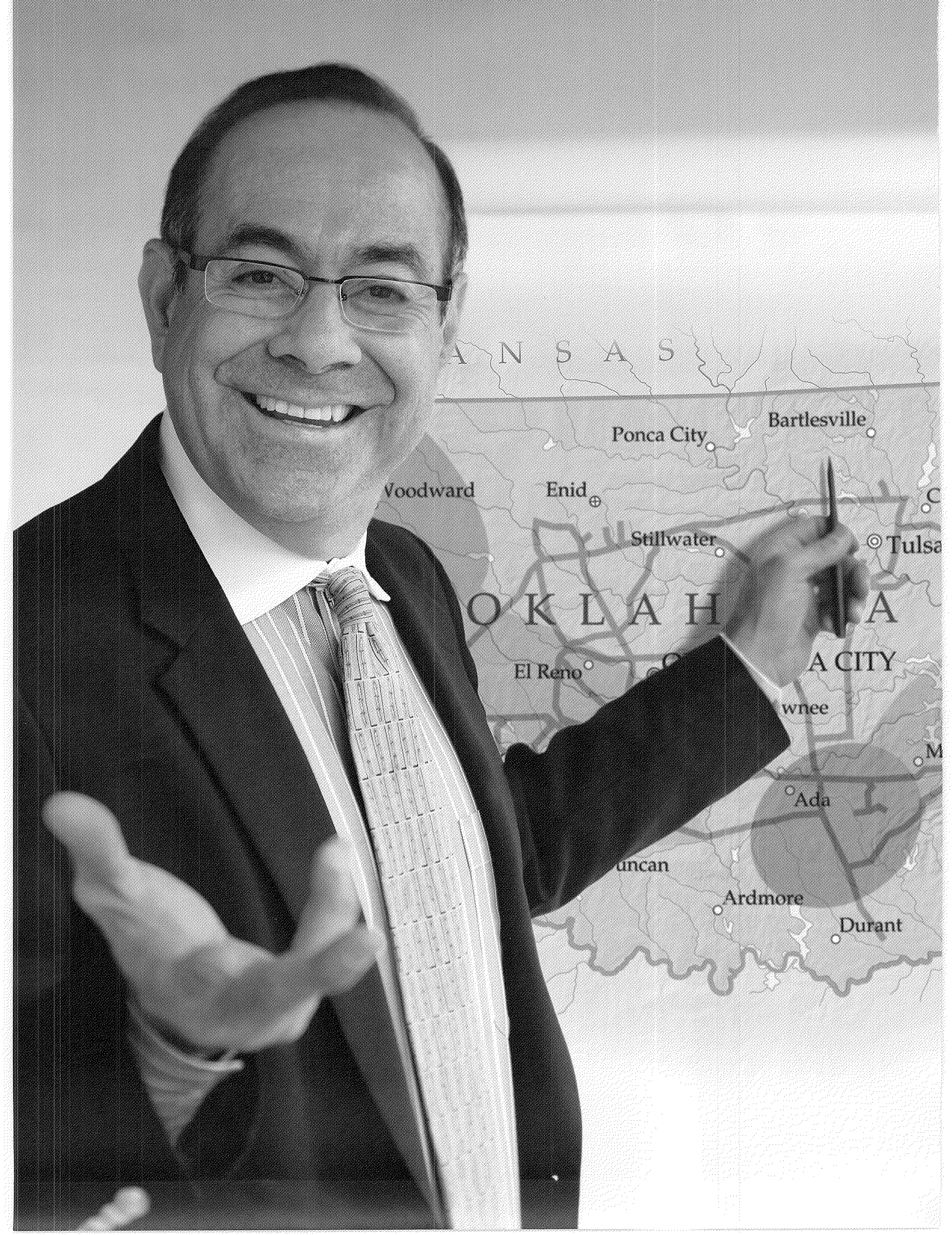
Left: Keith Limke, Shift Supervisor, OG&E Mustang Power Plant

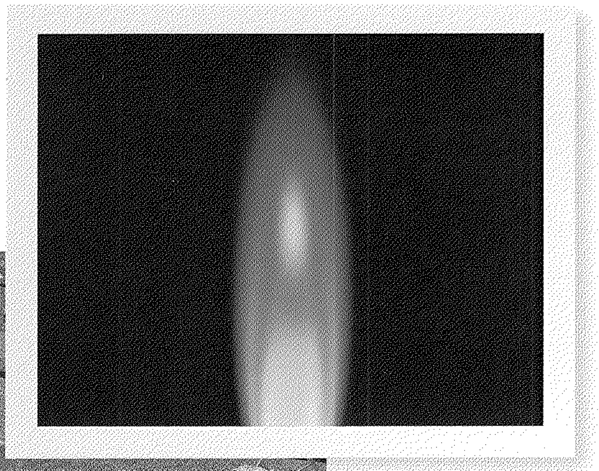
delivery

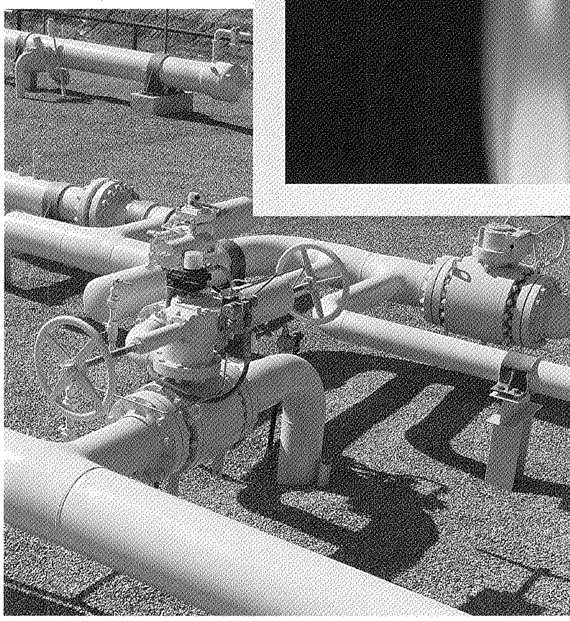
Delivering energy where and when it's needed requires sound planning, thoughtful public policy and careful execution of projects to build and maintain reliable systems.






Ponca City
Bartlesville
Woodward
Enid
Stillwater
Tulsa
El Reno
Ada
Ardmore
Durant

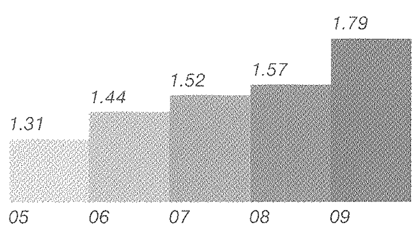




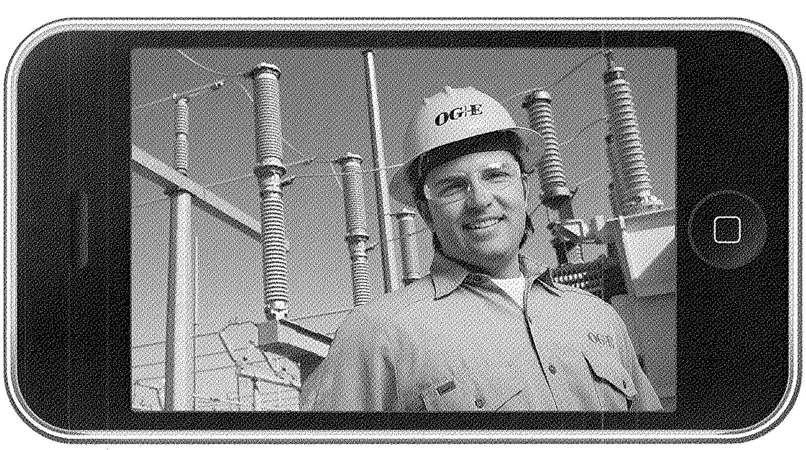
Geography is an advantage that positions both Enogex and OG&E for growth to meet the expanding infrastructure needs in natural gas and electricity.

Enogex continues a system expansion program that has totaled more than $800 million in the last five years, including the 2009 addition of the Clinton gas-processing plant. Investments like these have attracted greater natural gas volumes to the Enogex pipeline, even as commodity prices have some producers scaling back their drilling programs. Enogex also is enhancing growth and increasing stability with more fixed-fee, high-volume transportation capacity leased to cross-country gas shippers.

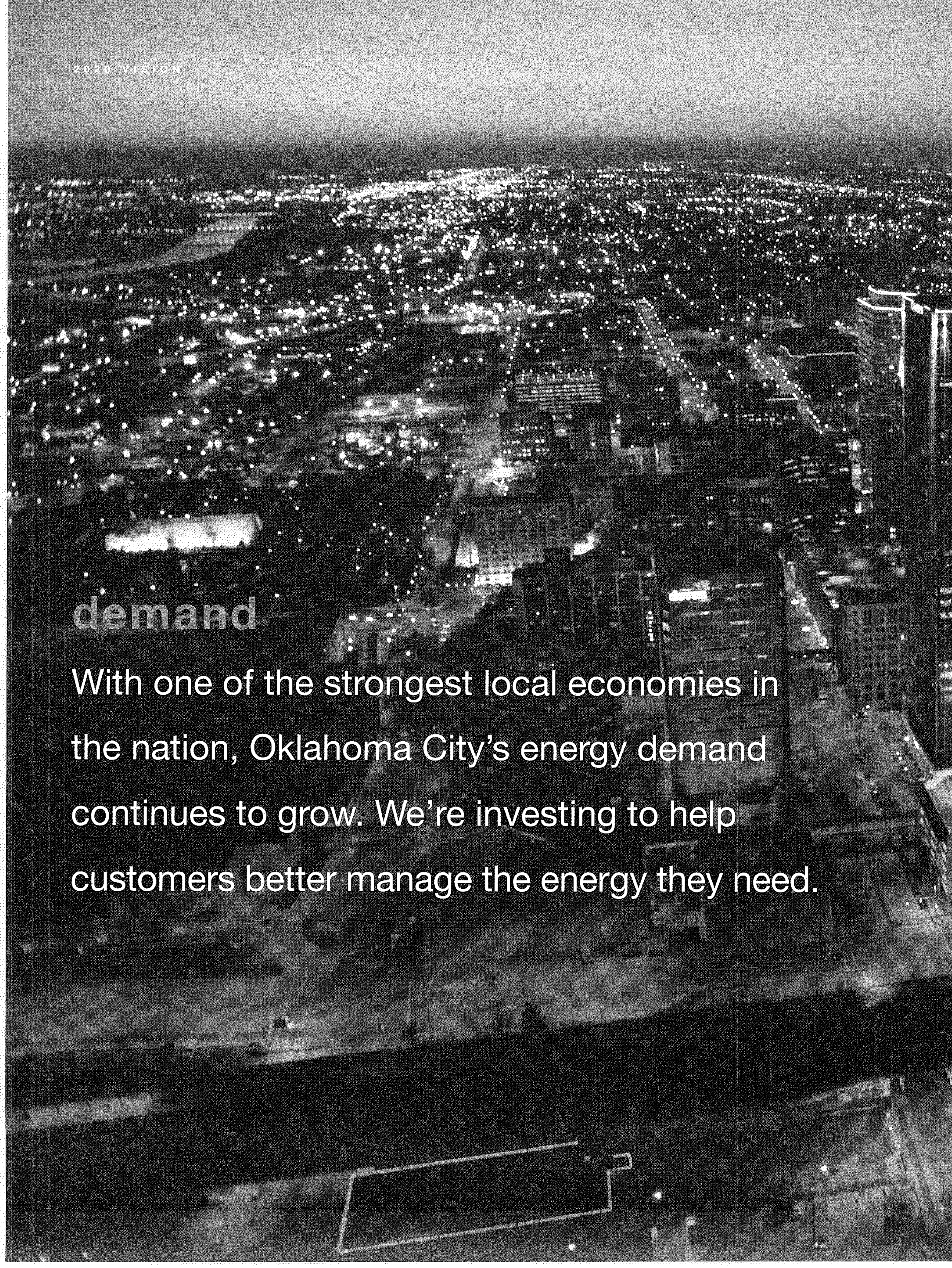
OG&E has 527 miles of known and committed electric transmission lines in various stages of completion, with the go-ahead from the regional transmission operating authority to construct some 25 projects. Altogether, they could represent a 20 percent increase in total assets for OG&E.



System Expansion
Enogex total gas throughput volumes (trillion Btu per day)

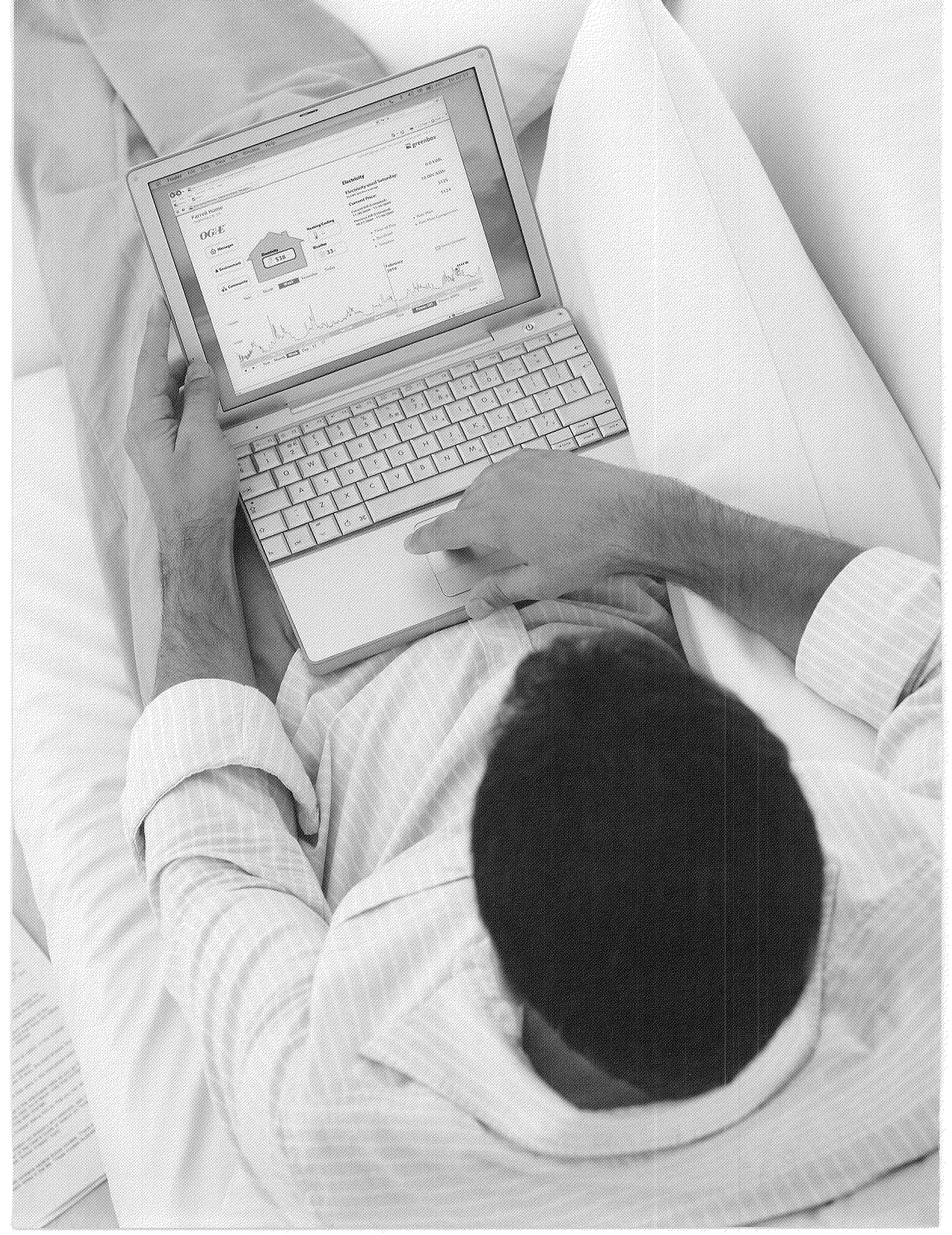


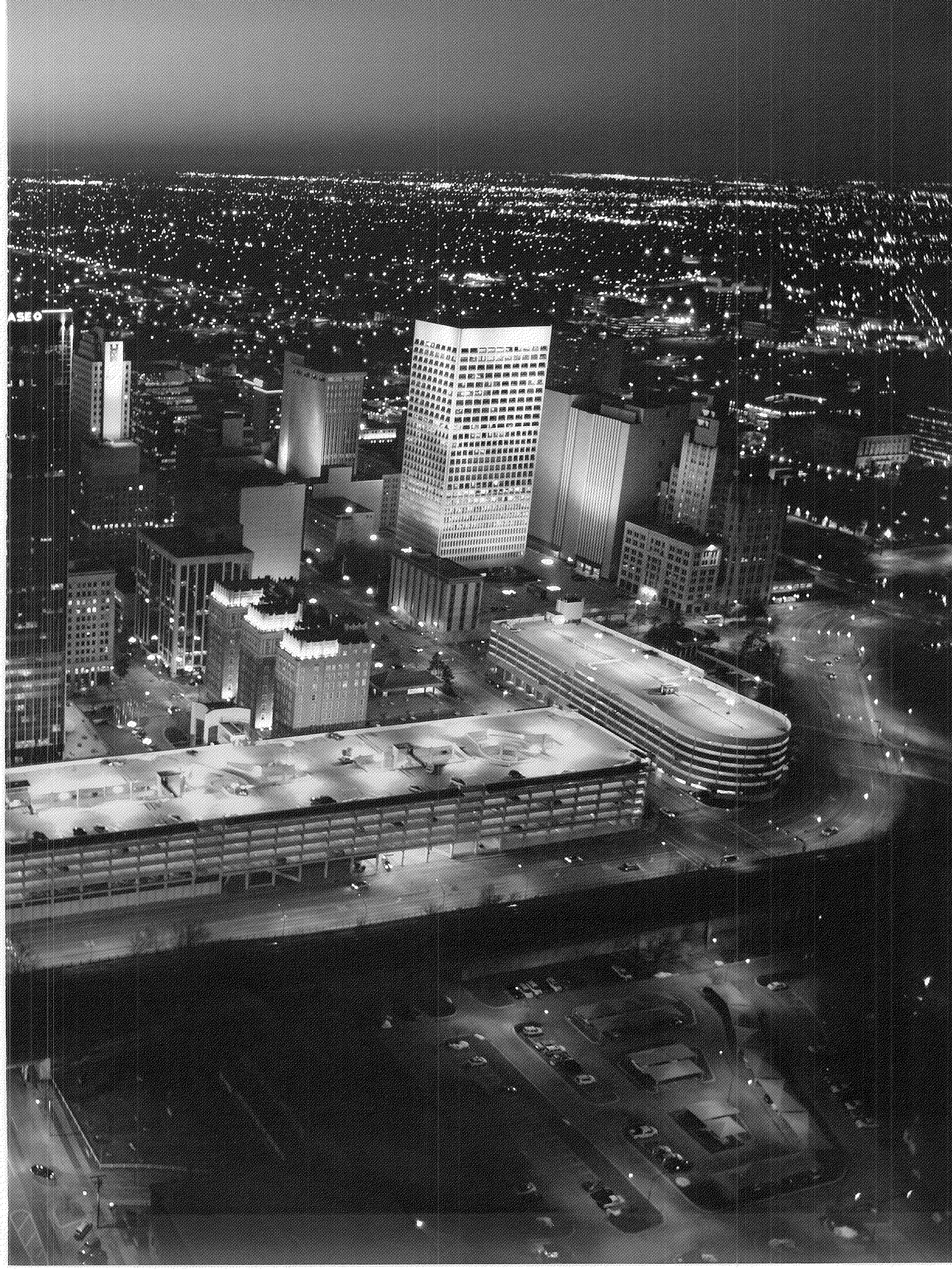
Left: Ramiro Rangel, Vice President, Enogex Commercial Operations
Above: Tony Wynd, Maintenance Technician, OG&E Substation Operations



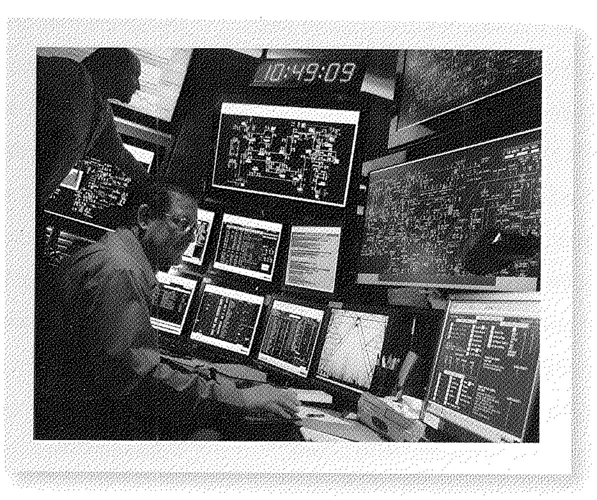
demand

With one of the strongest local economies in the nation, Oklahoma City's energy demand continues to grow. We're investing to help customers better manage the energy they need.


OG&E
greenbox
Electricity
Electricity used Saturday:
Current Price:



42,000 *OGE smart meters to be installed in 2010*



OG&E's smart grid program will use automated metering, in-home demand-response programs, and new technology to improve reliability. Few, if any, utilities are doing all of this at the same time. Our program attracted $130 million of federal stimulus funding, and we have filed with state regulators for additional funds that would enable OG&E to install smart meters systemwide in just three years.

We're also expanding demand-management programs including load reduction incentives for businesses and weatherization for homes. We even certify new houses built to stringent energy-efficiency standards as OG&E Positive Energy® homes – a strong selling point for builders and buyers.

All of this, in a constructive regulatory climate, supports our 2020 plan. And with our award-winning *Positive Energy Together®* campaign, we're partnering with our customers to help them identify ways to save. It's an important part of our plan to meet our 2020 goal.

Above: Rock Mason and Jay Chase, System Operators, OG&E Transmission Operations

OGE Energy Corp. improved earnings by 7 percent in 2009 and increased dividends for the fourth year in a row. Both OG&E and Enogex strengthened their growth potential with investments in utility and pipeline systems that expand their capacity to serve customers and improve the stability of returns for investors. Across all lines of business, OGE has controlled costs and improved operations, elevating consolidated financial performance.

When we talk about *Next Generation*, we're focused on creating value for customers and investors in the years ahead. At the same time, we're adhering to our core values and beliefs to ensure we do things the right way; ever mindful of how our decisions might affect our children and grandchildren.

As we formulate and execute our strategy, we remain keenly aware of the important role our companies play in the everyday lives of our customers and communities. We must continue to meet their needs safely, reliably and efficiently. In these areas, we are pleased to report that our 3,400 employees are doing a great job.

2020 Plan

An important part of the plan for our utility business is to delay the expense of additional fossil-fueled electric generation at least until 2020. This goal keys off the timely acquisition of the natural gas-fired Redbud power plant and the 600 megawatts it added to OG&E's generating fleet in 2009.

Redbud helps make the 2020 objective attainable, but historical load growth suggests our existing power plants alone won't be able to get us there. So we're also implementing demand-management programs and laying the foundation for more innovative approaches with smart meters.

This strategy gives us time before we must make our next big generation decision, allowing for greater clarity to materialize on environmental regulation and technology development. Meanwhile, we're executing on our key initiatives by investing in natural gas pipeline systems, wind power, electric transmission and smart grid.

Managing Demand

The next generation of the electric meter is coming to OG&E's customers in Norman, Oklahoma, an important step toward a smart system that promises benefits for customers and investors alike. The new meter, supported by in-home technology and new electricity pricing models, will give customers opportunities to make energy-use decisions that drive demand to lower-cost hours of the day, an outcome consistent with our 2020 plan.

We are supporting this with load curtailment and energy efficiency programs approved by state regulators; with a goal to restrain electric load growth in the decade ahead to a level 7 percent lower than we would expect without our various demand-management programs.

Peter B. Delaney
Chairman, President and Chief Executive Officer

Win-Win Projects

We are well on our way to our near-term goal of 770 megawatts of wind power. In addition to its environmental benefits, wind creates value by cushioning the impact of fuel price spikes. We added the 101-megawatt OU Spirit wind farm in 2009; and we've also obtained regulatory approval for power purchase agreements that will add 280 megawatts from new wind farms to be built in 2010. By the end of the year we expect to have 550 megawatts of wind energy on our system.

We've also built a key electric transmission link for more wind energy. It comes online in 2010 and should encourage the further development of the region's abundant wind resource. We also are working on other high-voltage transmission lines, including some on the Southwest Power Pool's list of projects to ensure the reliability of the regional power grid.

We look forward to these and other utility investments that will help us increase earnings and, at the same time, create savings for customers. Smart grid, transmission, wind farms and demand-management investments all contain such win-win opportunities.

Investing for Growth

System expansion helped Enogex weather the economic downturn in 2009 and now we're seeing a rebound in several rich natural gas producing areas. Investments in our gathering systems, our transportation system to support deliveries outside the state, and a new processing plant have driven our expansion. We've also reduced volatility in our gas-processing business through an emphasis on contracts with fixed fee terms. Looking ahead, we continue to see opportunities for solid returns from new projects in key areas.

Earnings growth requires the right operating and financial capabilities working together. We have successfully managed spending and capital projects in response to business conditions and funded investments largely through internal cash flow. We have improved our credit profile while also increasing our growth objectives, and we plan to continue on this same path in the years ahead.

Our business environment today is marked by challenges and uncertainties. But we expect to continue on our path, focusing on serving our customers well, providing opportunities to our employees and delivering solid returns to our shareowners.

Sincerely,

Peter B. Delaney

What we said, what we did.

Low Rates

What we said: "Appropriate regulatory relief will enable us to continue a long record of reliable service at well below average rates."
– 2008 Annual Report, page 1

What we did: OG&E achieved seven separate settlement agreements and rate orders in Oklahoma and Arkansas that allow the company to recover infrastructure investments. Still, OG&E's retail rates are 21 percent below the regional average and 35 percent below the national average.

Crucial Link

What we said: "We're planning new transmission lines to serve a growing regional market and link rural wind farms with cities hungry for renewable energy."
– 2007 Annual Report, page 7

What we did: OG&E sought and received approval to build a 120-mile, 345-kilovolt line from Woodward to Oklahoma City, then successfully managed construction of the line. In 2010 it will begin providing the crucial link between Oklahoma's abundant wind resources and our major customer load centers.

Dividends Rising

What we said: "We have increased our annual dividend to $1.36 per share, but we don't want to stop there."
– 2006 Annual Report, page 11

What we did: In 2010 the dividend is higher for the fourth year in a row, at $1.45 per share. Even as OGE operates in a challenging economy, it is controlling costs and maintaining a strong financial position, while funding projects that benefit customers.

Focus Forward

What we said: "We will need new approaches that embrace renewables while also supporting innovative technologies for partnering with our customers."
– 2008 Annual Report, page 1

What we did: OG&E added the 101-megawatt OU Spirit wind farm and obtained regulatory approval for two more wind farms that will bring renewables to 550 megawatts – nearly 8 percent of total generating capacity. OG&E also launched an industry-leading smart grid program that attracted one of the largest stimulus grants in the country.

Financial Performance

OGE Energy Corp. Common Stock Data

	2009	2008	2007	2006	2005
Diluted earnings per share	$ 2.66	$ 2.49	$ 2.64	$ 2.84	$ 2.32
Diluted earnings per share from continuing operations	$ 2.66	$ 2.49	$ 2.64	$ 2.45	$ 1.77
Dividends paid per share	$ 1.42	$ 1.39	$ 1.36	$ 1.33	$ 1.33
Price range	$37.79 – 19.70	$36.23 – 19.56	$41.30 – 29.12	$40.58 – 26.34	$30.60 – 24.41
Price/earnings ratio – year end	13.9	10.3	13.6	13.9	11.4
Return on equity – average	13.1%	13.1%	14.9%	17.9%	16.0%
Diluted average common shares outstanding (millions)	97.2	92.8	92.5	92.1	90.8

Oklahoma Gas and Electric Company

(In millions except EPS, before elimination of inter-segment items)	2009	2008	2007	2006	2005
Operating revenues	$1,751	$1,960	$1,835	$1,746	$1,721
Gross margin on revenues	$ 955	$ 845	$ 810	$ 796	$ 727
Operating income	$ 354	$ 278	$ 292	$ 294	$ 232
Net income	$ 200	$ 143	$ 162	$ 149	$ 130
Diluted earnings per share	$ 2.06	$ 1.54	$ 1.75	$ 1.62	$ 1.43
Return on equity – average	10.4%	9.3%	12.0%	12.8%	12.0%
Total electricity sales (millions of megawatt hours)	26.9	28.2	27.1	26.4	26.1

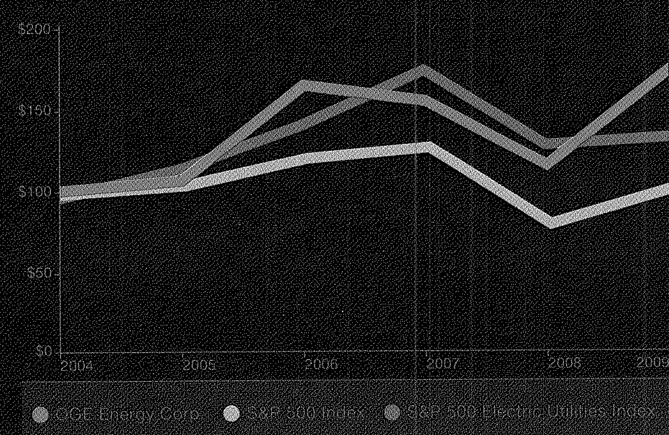
Enogex

(In millions except EPS, before elimination of inter-segment items)	2009	2008	2007	2006	2005
Operating revenues	$ 851	$1,103	$2,065	$2,368	$4,332
Gross margin on revenues	$ 360	$ 393	$ 353	$ 307	$ 242
Operating income	$ 146	$ 185	$ 164	$ 139	$ 90
Net income	$ 66	$ 91	$ 86	$ 114	$ 90
Diluted earnings per share	$ 0.68	$ 0.98	$ 0.93	$ 1.23	$ 0.99
Return on equity – average	15.7%	24.9%	21.9%	26.2%	18.5%
Pipeline throughput (TBtu/y)[A]	653	575	555	526	478

[A] Trillion British thermal units per year

Cumulative Five-Year Total Return

This graph shows a five-year comparison of cumulative total returns for the Company's common stock, the S&P 500 Index and the S&P 500 Electric Utilities Index. The graph assumes that the value of the investment in the Company's common stock and each index was $100 at Dec. 31, 2004, and that all dividends were reinvested. As of Dec. 31, 2009, the closing price of the Company's common stock on the New York Stock Exchange was $36.89.

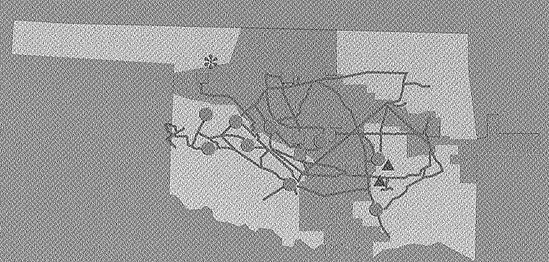


This is OGE

OGE Energy Corp. (NYSE: OGE), with headquarters in Oklahoma City, is the parent company of Oklahoma Gas and Electric Company (OG&E), a regulated electric utility, and Enogex LLC, a midstream natural gas pipeline business. OGE Energy and its subsidiaries have 3,400 employees.

2009 EARNINGS GROWTH	NO. OF ELECTRIC CUSTOMERS	ELECTRIC RATES BELOW THE NATIONAL AVERAGE BY
+7%	777k	35%

Electric Utility and Natural Gas Pipeline



Oklahoma Gas and Electric Company

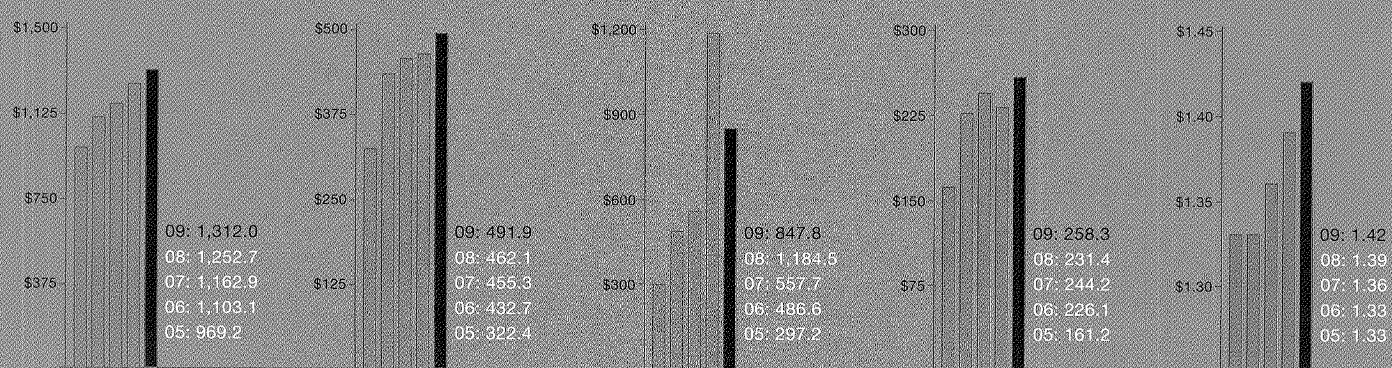
Oklahoma Gas and Electric Company serves approximately 777,000 retail customers in Oklahoma and western Arkansas. OG&E, with about 6,600 megawatts of capacity, generates electricity from low-sulfur Wyoming coal, natural gas and wind. OG&E's electric transmission and distribution systems cover an area of 30,000 square miles.

Enogex

Enogex operates a pipeline system engaged in natural gas gathering, processing, transportation and storage. The system includes about 8,000 miles of pipe, nine natural gas processing plants and 24 billion cubic feet of natural gas storage capacity.

2009 Highlights

Dollars in millions unless noted



Gross Margin on Revenues | Operating Income | Total Capital Expenditures | Net Income[1] | Dividends Paid per Share

[1] From continuing operations

Right: Debra Smith, Senior Asset Analyst, OG&E Power Delivery

Leadership

Senior Management

OGE Energy Corp.

Peter B. Delaney
Chairman, President and CEO
OGE Energy Corp., OG&E
Chairman and CEO
Enogex LLC

Danny P. Harris
Senior Vice President and
Chief Operating Officer
OGE Energy Corp., OG&E
President
Enogex LLC

Sean Trauschke
Vice President and
Chief Financial Officer
OGE Energy Corp., OG&E
Chief Financial Officer
Enogex LLC

Scott Forbes
Controller and
Chief Accounting Officer

Patricia D. Horn
Vice President, Governance &
Environmental Health & Safety;
Corporate Secretary

Gary D. Huneryager
Vice President, Internal Audits

S. Craig Johnston
Vice President, Strategic
Planning and Marketing

Cristina F. McQuistion
Vice President, Process and
Performance Improvement

Stephen E. Merrill
Vice President, Human Resources

Max J. Myers
Treasurer

Reid V. Nuttall
Vice President,
Chief Information Officer

Jerry A. Peace
Chief Risk Officer

Paul L. Renfrow
Vice President, Public Affairs

OG&E

Jesse B. Langston
Vice President
Utility Commercial Operations

Jean C. Leger, Jr.
Vice President, Utility Operations

Howard W. Motley
Vice President, Regulatory Affairs

Melvin H. Perkins, Jr.
Vice President, Power Delivery

Enogex LLC

E. Keith Mitchell
Senior Vice President and
Chief Operating Officer

Paul M. Brewer
Vice President, Operations

Thomas L. Levescy
Controller and
Chief Accounting Officer

Ramiro F. Rangel
Vice President,
Commercial Operations

OGE Energy Resources, Inc.

Craig R. Jimenez
President

Board of Directors

Peter B. Delaney
Chairman, President and CEO
OGE Energy Corp., OG&E
Chairman and CEO
Enogex LLC
Oklahoma City

Luke R. Corbett[3]
Former Chairman and
Chief Executive Officer,
Kerr-McGee Corporation
Oklahoma City

Robert Kelley[1]
President,
Kellco Investments Inc.
Ardmore, Oklahoma

Robert O. Lorenz[1,2]
Retired Managing Partner,
Arthur Andersen
Oklahoma City

Leroy C. Richie[2,3]
Counsel,
Lewis & Munday, P.C.
Detroit, Michigan

James H. Brandi[2,3]
Partner,
Hill Street Capital, LLC
New York City, New York

Wayne H. Brunetti[1,3]
Retired Chairman,
Xcel Energy Inc.
Denver, Colorado

John D. Groendyke[2,3]
Chairman and
Chief Executive Officer,
Groendyke Transport, Inc.
Enid, Oklahoma

Kirk Humphreys[1,3]
Chairman and Manager,
The Humphreys Company, LLC
and Manager,
Carlton Landing, LLC
Oklahoma City

Linda P. Lambert[1,2]
President,
LASSO Corporation
and Enertree, L.L.C.
Oklahoma City

[1] Member of the audit committee
[2] Member of the nominating and corporate governance committee
[3] Member of the compensation committee

Red number indicates committee chairman

We Live Here, Too

Our 108 years in business have clearly shown that what's good for our community is good for us. OG&E serves 269 cities and towns in Oklahoma and Arkansas; Enogex has operations and facilities in dozens more communities in Oklahoma and Texas. We have a vested interest in the success of every community we touch, and we embrace our role as a leader across an area spanning some 50,000 square miles.

$828,000

Employees' 2009 pledges to United Way

Received SEC

APR 1 - 2010

Washington, DC 20549

2009

Financial Section

OGE Energy Corp. Annual Report

Management's Discussion and Analysis of Financial Condition and Results of Operations

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in this Annual Report, including those matters discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential", "project" and similar expressions. Actual results may vary materially. In addition to the specific risk factors discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein, factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- General economic conditions, including the availability of credit, access to existing lines of credit, actions of rating agencies and their impact on capital expenditures;
- The ability of OGE Energy Corp. (collectively, with its subsidiaries, the "Company") and its subsidiaries to access the capital markets and obtain financing on favorable terms;
- Prices and availability of electricity, coal, natural gas and natural gas liquids, each on a stand-alone basis and in relation to each other;
- Business conditions in the energy and natural gas midstream industries;
- Competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company;
- Unusual weather;
- Availability and prices of raw materials for current and future construction projects;
- Federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company's markets;
- Environmental laws and regulations that may impact the Company's operations;
- Changes in accounting standards, rules or guidelines;
- The discontinuance of accounting principles for certain types of rate-regulated activities;
- Creditworthiness of suppliers, customers and other contractual parties;
- The higher degree of risk associated with the Company's nonregulated business compared with the Company's regulated utility business; and
- Other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission.

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.

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 Oklahoma Gas and Electric Company ("OG&E") and are subject to rate regulation by the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

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

Executive Overview

Strategy

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

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

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

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

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

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

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

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

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

Summary of Operating Results

2009 compared to 2008

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

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

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

2008 compared to 2007

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

- Net income at OG&E of approximately $143.0 million in 2008 as compared to approximately $161.7 million in 2007, which was a decrease in net income of approximately $18.7 million, or $0.21 per diluted share of the Company's common stock, in 2008 as compared to 2007 primarily due to higher operation and maintenance expense, higher depreciation and amortization expense, higher other expense and higher interest expense partially offset by a higher gross margin due to increased rates from various regulatory riders implemented in 2008 and lower income tax expense;
- Net income at Enogex of approximately $91.2 million in 2008 as compared to approximately $86.2 million in 2007, which was an increase in net income of approximately $5.0 million, or $0.05 per diluted share of the Company's common stock, in 2008 as compared to 2007 primarily due to a higher gross margin partially offset by higher operation and maintenance expense, higher depreciation and amortization expense, lower interest income, higher other expense and higher income tax expense. Net income for Enogex in 2007 included net income of approximately $10.9 million, or $0.12 per diluted share, attributable to OERI;

- Net income at OERI of approximately $4.4 million, or $0.05 per diluted share of the Company's common stock, in 2008; and
- Net loss at OGE Energy of approximately $7.2 million in 2008 as compared to approximately $3.7 million in 2007, which was an increase in the net loss of approximately $3.5 million, or $0.03 per diluted share of the Company's common stock, in 2008 as compared to 2007 primarily due to higher operation and maintenance expense related to the 2008 write-off of transaction costs incurred related to the proposed joint venture between OGE Energy and Energy Transfer Partners, L.P. that was terminated and transaction costs associated with the formation of OGE Enogex Partners, L.P. of approximately $8.8 million, partially offset by lower interest expense due to lower advances from subsidiaries, higher other income due to receiving life insurance proceeds in 2008 from the death of one of the Company's directors in 2008 and a higher income tax benefit due to a higher net loss.

Timing Items

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

Recent Developments and Regulatory Matters

Changes in the Capital and Commodity Markets

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

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

Global Climate Change and Environmental Concerns

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

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

OG&E 2009 Oklahoma Rate Case Filing

On February 27, 2009, OG&E filed its rate case with the OCC requesting a rate increase of approximately $110 million. On July 24, 2009, the OCC issued an order authorizing: (i) an annual net increase of approximately $48.3 million in OG&E's rates to its Oklahoma retail customers, which includes an increase in the residential customer charge from $6.50/month to $13.00/month, (ii) creation of a new recovery rider to permit the recovery of up to $20 million of capital expenditures and operation and maintenance expenses associated with OG&E's smart grid project in Norman, Oklahoma, which was implemented in February 2010, (iii) continued utilization of a return on equity of 10.75 percent under various recovery riders previously approved by the OCC and (iv) recovery through OG&E's fuel adjustment clause of approximately $4.8 million annually of certain expenses that historically had been recovered through base rates. New electric rates were implemented August 3, 2009. OG&E expects the impact of the rate increase on its customers and service territory to be minimal over the next 12 months as the rate increase will be more than offset by lower fuel costs attributable to prior fuel over recoveries and from lower than forecasted fuel costs in 2010.

OG&E Arkansas Rate Case Filing

In August 2008, OG&E filed with the APSC an application for an annual rate increase of approximately $26.4 million to recover, among other things, costs for investments including in the Redbud Facility and improvements in its system of power lines, substations and related equipment to ensure that OG&E can reliably meet growing customer demand for electricity. On May 20, 2009, the APSC approved a general rate increase of approximately $13.3 million, which excludes approximately $0.3 million in storm costs discussed below. The APSC order also allows implementation of OG&E's "time-of-use" tariff which allows participating customers to save on their electricity bills by shifting some of the electricity consumption to times when demand for electricity is lowest. OG&E implemented the new electric rates effective June 1, 2009.

OG&E OU Spirit Wind Power Project

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

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

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

OG&E Renewable Energy Filing

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

OG&E Smart Grid Application

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

Agreement with Midcontinent Express Pipeline, LLC

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

Enogex FERC Section 311 2009 Rate Case

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

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

Gathering and Processing System Expansions

Southeastern Oklahoma / East Side Expansions

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

Texas Panhandle / West Side Expansions

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

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

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

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

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

Enogex Additional Processing Capacity

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

Transportation System Expansions

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

2010 Outlook

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

Key factors and assumptions for 2010 include:

Consolidated OGE Energy

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

OG&E

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

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

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

Enogex

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

- Total Enogex anticipated gross margin of approximately $370 million to $400 million. The gross margin assumption includes:
  - Transportation and storage gross margin contribution of approximately $150 million to $160 million, of which approximately 20 percent is attributable to the storage business;
  - Gathering and processing gross margin contribution of approximately $220 million to $240 million, with equal contributions to gross margin from each business;

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

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

(In millions, twelve months ended December 31)	2010 (A)
Reconciliation of projected EBITDA to projected net income	
Net income attributable to Enogex LLC	$ 74.0
Add:	
Interest expense, net	33.0
Income tax expense	49.0
Depreciation and amortization	69.0
EBITDA	$225.0

(A) *Based on midpoint of 2010 guidance.*

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

Dividend Policy

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

Results of Operations

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

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

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

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

(A) *On January 1, 2008, Enogex distributed the stock of OERI to OGE Energy, and as a result, OERI is no longer a subsidiary of Enogex.*
(B) *Other Operations primarily includes the operations of the holding company and consolidating eliminations.*

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

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

(A) *Sales to other utilities and power marketers.*
(B) *Megawatt-hour.*
(C) *Kilowatt-hour.*
(D) *Degree days are calculated as follows: The high and low degrees of a particular day are added together and then averaged. If the calculated average is above 65 degrees, then the difference between the calculated average and 65 is expressed as cooling degree days, with each degree of difference equaling one cooling degree day. If the calculated average is below 65 degrees, then the difference between the calculated average and 65 is expressed as heating degree days, with each degree of difference equaling one heating degree day. The daily calculations are then totaled for the particular reporting period.*

2009 compared to 2008

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

Gross Margin

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

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

These increases in the gross margin were partially offset by:

- Milder weather in OG&E's service territory, which decreased the gross margin by approximately $18.2 million; and
- Lower demand and related revenues by non-residential customers in OG&E's service territory, which decreased the gross margin by approximately $8.1 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was approximately $618.5 million in 2009 as compared to approximately $857.2 million in 2008, a decrease of approximately $238.7 million, or 27.8 percent, primarily due to lower natural gas prices. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. In 2009, OG&E's fuel mix was 60 percent coal, 38 percent natural gas and two percent wind. In 2008, OG&E's fuel mix was 68 percent coal, 30 percent natural gas and two percent wind. Purchased power costs were approximately $176.6 million in 2009 as compared to approximately $257.0 million in 2008, a decrease of approximately $80.4 million, or 31.3 percent, primarily due to the termination of the purchase power agreement with the Redbud Facility following OG&E's purchase of the Redbud Facility in September 2008 as well as a decrease in purchases in the energy imbalance service market.

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

Operating Expenses

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

- A decrease of approximately $13.2 million in contract technical and construction services attributable to decreased spending on overhauls at some of OG&E's power plants in 2009 as compared to 2008 and utilization of employees instead of contracting external labor;
- A decrease of approximately $9.5 million due to a correction of the over-capitalization of certain payroll, benefits, other employee related costs and overhead costs in previous years in March 2008, as discussed in Note 12 of Notes to Consolidated Financial Statements;
- An increase in capitalized labor in 2009 as compared to 2008, which decreased other operation and maintenance expenses by approximately $7.7 million;
- A decrease of approximately $3.8 million in fleet transportation expense primarily due to lower fuel costs in 2009; and
- A decrease of approximately $3.2 million due to the reclassification of 2006 and 2007 pension settlement costs to a regulatory asset due to the Arkansas rate case settlement, as discussed in Note 1 of Notes to Consolidated Financial Statements.

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

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

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

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

Additional Information

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

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

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

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

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

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

These increases in interest expense were partially offset by:

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

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

2008 compared to 2007

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

Gross Margin

Gross margin was approximately $844.6 million in 2008 as compared to approximately $810.0 million in 2007, an increase of approximately $34.6 million, or 4.3 percent. The gross margin increased primarily due to:

- New revenues from the Redbud Facility rider and the storm cost recovery rider, which increased the gross margin by approximately $21.1 million;
- New customer growth in OG&E's service territory, which increased the gross margin by approximately $8.4 million; and
- Increased demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by approximately $5.0 million.

Fuel expense was approximately $857.2 million in 2008 as compared to approximately $756.1 million in 2007, an increase of approximately $101.1 million, or 13.4 percent, primarily due to higher natural gas prices. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. In 2008, OG&E's fuel mix was 68 percent coal, 30 percent natural gas and two percent wind. In 2007, OG&E's fuel mix was 62 percent coal, 36 percent natural gas and two percent wind. Purchased power costs were approximately $257.0 million in 2008 as compared to approximately $268.6 million in 2007, a decrease of approximately $11.6 million, or 4.3 percent, primarily due to lower purchases from the energy imbalance service market partially offset by capacity payments made to Redbud due to the purchase power agreement in effect prior to OG&E's purchase of the Redbud Facility in September 2008.

Operating Expenses

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

- A decrease in capitalized work of approximately $14.0 million primarily related to costs related to the 2007 ice storm that were deferred as a regulatory asset;
- An increase of approximately $9.5 million due to a correction of the overcapitalization of certain payroll, benefits, other employee related costs and overhead costs in previous years in March 2008, as discussed in Note 12 of Notes to Consolidated Financial Statements;
- An increase of approximately $6.9 million in salaries and wages expense primarily due to hiring additional employees to support OG&E's operations as well as salary increases in 2008;
- An increase of approximately $6.6 million in contract technical and construction services expense and approximately $1.5 million in materials and supplies expense primarily attributable to overhaul expenses at several of OG&E's power plants in 2008;
- An increase of approximately $5.3 million due to increased spending on vegetation management;
- An increase of approximately $2.2 million in fleet transportation expense primarily due to higher fuel and maintenance costs in 2008; and
- An increase of approximately $1.3 million in professional services expense primarily due to higher engineering consulting services in 2008 as compared to 2007.

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

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

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

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

Additional Information

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

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

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

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

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

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

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

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

(In millions, year ended December 31)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
2009					
Operating revenues	**$401.0**	**$ 657.5**	**$ –**	**$(207.6)**	**$ 850.9**
Cost of goods sold	**239.9**	**458.8**	**–**	**(207.6)**	**491.1**
Gross margin on revenues	**161.1**	**198.7**	**–**	**–**	**359.8**
Other operation and maintenance	**40.9**	**87.2**	**–**	**–**	**128.1**
Depreciation and amortization	**20.4**	**43.9**	**–**	**–**	**64.3**
Impairment of assets	**0.9**	**1.9**	**–**	**–**	**2.8**
Taxes other than income	**13.2**	**5.5**	**–**	**–**	**18.7**
Operating income	**$ 85.7**	**$ 60.2**	**$ –**	**$ –**	**$ 145.9**
2008					
Operating revenues	$625.9	$1,053.2	$ –	$(575.9)	$1,103.2
Cost of goods sold	479.7	806.4	–	(575.9)	710.2
Gross margin on revenues	146.2	246.8	–	–	393.0
Other operation and maintenance	48.2	87.3	–	–	135.5
Depreciation and amortization	17.5	37.1	–	–	54.6
Impairment of assets	–	0.4	–	–	0.4
Taxes other than income	12.7	4.6	–	–	17.3
Operating income	$ 67.8	$ 117.4	$ –	$ –	$ 185.2
2007					
Operating revenues	$529.1	$799.4	$1,541.2	$(804.5)	$2,065.2
Cost of goods sold	396.4	603.5	1,513.4	(801.2)	1,712.1
Gross margin on revenues	132.7	195.9	27.8	(3.3)	353.1
Other operation and maintenance	48.5	72.1	10.1	(3.3)	127.4
Depreciation and amortization	17.0	28.7	0.2	–	45.9
Impairment of assets	0.5	–	–	–	0.5
Taxes other than income	11.7	3.7	0.4	–	15.8
Operating income	$ 55.0	$ 91.4	$ 17.1	$ –	$ 163.5

Operating Data – Continuing Operations

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

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

[B] Incremental transportation volumes consist of natural gas moved only on the transportation pipeline.

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

2009 compared to 2008

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

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

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

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

Transportation and Storage

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

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

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

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

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

Gathering and Processing

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

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

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

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

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

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

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

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

Enogex Consolidated Information

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

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

- An increase in interest expense of approximately $8.9 million on the $200 million of 6.875% 5-year senior notes issued in June 2009 and the $250 million of 6.25% 10-year senior notes issued in November 2009; and

- An increase in interest expense of approximately $3.0 million due to a tender payment on the tender offer Enogex completed in July 2009 for the purchase of approximately $110.8 million of Enogex's $400.0 million 8.125% senior notes outstanding that matured on January 15, 2010.

These increases in interest expense were partially offset by:

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

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

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

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

2008 compared to 2007

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

Gross Margin

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

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

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

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

- Enogex's transportation operations moving from an under-recovered position to an over-recovered position under its FERC-approved fuel tracker in the East Zone in 2008, which resulted in a loss compared to a gain in 2007, which decreased the gross margin by approximately $8.0 million;
- Lower gross margins on realized operational storage hedges in 2008 as compared to 2007, which decreased the gross margin by approximately $2.9 million;
- Lower gross margins on commodity and interruptible storage fees resulting from the loss of a contract in 2008 and decreased activity due to changes in the marketplace, which decreased the gross margin by approximately $1.2 million; and

- The removal of a liability associated with a throughput contract which was transferred to the gathering and processing segment during 2007 with no comparable item recorded in 2008, which increased the 2007 gross margin by approximately $1.2 million.

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

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

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

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

Operating Expenses

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

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

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

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

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

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

Enogex Consolidated Information

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

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

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

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

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

2009 compared to 2008

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

Gross Margin

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

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

Operating Expenses

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

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

Additional Information

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

2008 compared to 2007

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

Gross Margin

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

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

These decreases in the gross margin were partially offset by:

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

Operating Expenses

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

Additional Information

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

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

Enogex's Non-GAAP Financial Measure

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

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

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

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

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

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

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

Financial Condition

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

At December 31, 2009, OG&E had a noncancellable operating lease with purchase options, covering 1,462 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. At the end of the lease term, which is January 31, 2011, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of approximately $31.5 million.

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

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

Liquidity and Capital Requirements

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and Enogex. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, hedging activities, delays in recovering unconditional fuel purchase obligations, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings. See "Future Sources of Financing – Short-Term Debt" for information regarding the Company's revolving credit agreements and commercial paper.

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

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

[(A)] *These capital expenditures are contingent upon OCC approval of OG&E's Positive Energy Smart Grid program and are net of the Smart Grid $130 million grant approved by the DOE.*

[(B)] *The Base Capital Expenditure Plan above excludes any environmental expenditures associated with Best Available Retrofit Technology ("BART") requirements due to the uncertainty regarding BART costs. As discussed in "– Environmental Laws and Regulations" below, pursuant to a proposed regional haze agreement OG&E has agreed to install low nitrogen oxide ("NOX") burners and related equipment at the three affected generating stations. Preliminary estimates indicate the cost will be approximately $100 million (plus or minus 30 percent). For further information, see "– Environmental Laws and Regulations" below.*

[(C)] *Includes expected recoveries of costs incurred for OG&E's railcar operating lease obligations, OG&E's cogeneration capacity payments, OG&E's unconditional fuel purchase obligations and OG&E's wind purchase commitments.*

N/A – not available

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

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

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

2009 Capital Requirements and Financing Activities

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

Long-Term Debt Maturities

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

Net Available Liquidity

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

Potential Collateral Requirements

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

Cash Flows

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Future Capital Requirements and Financing Activities

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

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

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

Pension and Postretirement Benefit Plans

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

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

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

(In millions)	OG&E [A]	Enogex	OGE Energy	Total
Pension settlement charge:				
2007	$13.3	$0.5	$2.9	$16.7
Retirement restoration plan settlement charge:				
2007	$ 0.1	$ –	$2.2	$ 2.3

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

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

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

Pension Plan Costs and Assumptions

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

Security Ratings

	Moody's	Standard & Poor's	Fitch's
OG&E senior notes	A2	BBB+	AA-
Enogex notes	Baa3	BBB+	BBB
OGE Energy Corp. senior notes	Baa1	BBB	A
OGE Energy Corp. commercial paper	P2	A2	F1

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

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

Future Sources of Financing

Management expects that cash generated from operations, proceeds from the issuance of long and short-term debt and proceeds from the sales of common stock to the public through the Company's DRIP/DSPP or other offerings will be adequate over the next three years to meet anticipated cash needs. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt

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

(In millions)	Aggregate Commitment	Amount Outstanding	Weighted-Average Interest Rate	Maturity
Revolving credit agreements and available cash				
OGE Energy	$ 596.0	$175.0	0.27%	12/6/12
OG&E	389.0	10.2	0.14%	12/6/12
Enogex	250.0	–	–	3/31/13
	1,235.0	185.2	0.26%	
Cash	58.1	N/A	N/A	N/A
Total	$1,293.1	$185.2	0.26%	

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

Registration Statement Filing

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

Expected Issuance of OG&E Long-Term Debt

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

Common Stock

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

Income Tax Refund

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

Critical Accounting Policies and Estimates

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

Consolidated (including all Company segments)

Pension and Postretirement Benefit Plans

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

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

Impairment of Assets

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

Commitments and Contingencies

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

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

Asset Retirement Obligations

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

Hedging Policies

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

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

Electric Utility Segment

Regulatory Assets and Liabilities

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

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

Unbilled Revenues

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

Allowance for Uncollectible Accounts Receivable

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

Natural Gas Transportation and Storage and Gathering and Processing Segments
Operating Revenues

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

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

Natural Gas Purchases

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

Natural Gas Inventory

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

Allowance for Uncollectible Accounts Receivable

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

Marketing Segment
Operating Revenues

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

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

Natural Gas Purchases

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

Purchase and Sale Contracts

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

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

Natural Gas Inventory

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

Allowance for Uncollectible Accounts Receivable

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

Accounting Pronouncements

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

Commitments and Contingencies

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

Environmental Laws and Regulations

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

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

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

Air

Federal Clean Air Act

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

Mercury and Hazardous Air Pollutants

On March 15, 2005, the U.S. Environmental Protection Agency ("EPA") issued the Clean Air Mercury Rule ("CAMR") to limit mercury emissions from coal-fired boilers. On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit Court vacated the rule. In January 2010, the EPA issued an information collection request which will survey power plant operators about their emissions of mercury and other hazardous air pollutants ("HAP"). The EPA has announced plans to promulgate new HAP emission limitations for coal-fired and oil-fired power plants by November 2011. Any costs associated with future regulation of mercury or other HAPs are uncertain at this time. Because of the uncertainty caused by the litigation regarding the CAMR, the promulgation of an Oklahoma rule that would have applied to existing facilities has also been delayed. OG&E will continue to participate in the state rule making process.

RICE MACT Amendments

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

Regional Haze

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

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

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

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

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

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

Sulfur Dioxide

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

On November 16, 2009, the EPA proposed a new one-hour National Ambient Air Quality Standard ("NAAQS") for SO2 to address public health concerns. The EPA is proposing to revise the primary SO2 standard to a level of between 50 and 100 parts per billion ("PPB") measured over one-hour. The EPA is under a consent decree to take final action by June 2, 2010. The proposal was published in the Federal Register on December 8, 2009. Oklahoma is in attainment with the current three-hour and 24-hour SO2 NAAQS; however, a one-hour standard less than 100 PPB may result in certain areas not meeting attainment. If parts of Oklahoma do become "non-attainment", reductions in emissions from OG&E's coal-fired boilers could be required, which may result in significant capital and operating expenditures.

Ozone

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

Greenhouse Gases

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

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

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

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

Legislation

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

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

Water

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

Quantitative and Qualitative Disclosures About Market Risk

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

Risk Committee and Oversight

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

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

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

Risk Policies

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

Interest Rate Risk

The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt, treasury lock agreements and commercial paper. The Company from time to time uses treasury lock agreements to manage its interest rate risk exposure on new debt issuances. Additionally, the Company manages its interest rate exposure by limiting its variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce interest expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

The fair value of the Company's long-term debt is based on quoted market prices and management's estimate of current rates available for similar issues with similar maturities. At December 31, 2009 and 2008, the Company had no outstanding treasury lock agreements. The following table shows the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

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

(A) *Prior to or when these debt obligations mature, the Company may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt.*

(B) *A hypothetical change of 100 basis points in the underlying variable interest rate would change interest expense by approximately $1.4 million annually.*

Commodity Price Risk

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

Trading Activities

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

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

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

Non-Trading Activities

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

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

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

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

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

Consolidated Statements of Income

(In millions, except per share data, year ended December 31)	**2009**	2008	2007
Operating revenues			
Electric Utility operating revenues	**$1,751.2**	$1,959.5	$1,835.1
Natural Gas Pipeline operating revenues	**1,118.5**	2,111.2	1,962.5
Total operating revenues	**2,869.7**	4,070.7	3,797.6
Cost of goods sold (exclusive of depreciation and amortization shown below)			
Electric Utility cost of goods sold	**748.7**	1,061.2	977.8
Natural Gas Pipeline cost of goods sold	**809.0**	1,756.8	1,656.9
Total cost of goods sold	**1,557.7**	2,818.0	2,634.7
Gross margin on revenues	**1,312.0**	1,252.7	1,162.9
Other operation and maintenance	**466.8**	492.2	436.8
Depreciation and amortization	**262.6**	217.5	195.3
Impairment of assets	**3.1**	0.4	0.5
Taxes other than income	**87.6**	80.5	75.0
Operating income	**491.9**	462.1	455.3
Other income (expense)			
Interest income	**1.4**	6.7	2.1
Allowance for equity funds used during construction	**15.1**	–	–
Other income	**27.5**	15.4	17.4
Other expense	**(16.3)**	(25.6)	(22.7)
Net other income (expense)	**27.7**	(3.5)	(3.2)
Interest expense			
Interest on long-term debt	**137.3**	103.0	87.8
Allowance for borrowed funds used during construction	**(8.3)**	(4.0)	(4.0)
Interest on short-term debt and other interest charges	**8.4**	21.0	6.4
Interest expense	**137.4**	120.0	90.2
Income before taxes	**382.2**	338.6	361.9
Income tax expense	**121.1**	101.2	116.7
Net income	**261.1**	237.4	245.2
Less: net income attributable to noncontrolling interest	**2.8**	6.0	1.0
Net income attributable to OGE Energy	**$ 258.3**	$ 231.4	$ 244.2
Basic average common shares outstanding	**96.2**	92.4	91.7
Diluted average common shares outstanding	**97.2**	92.8	92.5
Basic earnings per average common share attributable to OGE Energy common shareholders	**$ 2.68**	$ 2.50	$ 2.66
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$ 2.66**	$ 2.49	$ 2.64
Dividends declared per share	**$ 1.4275**	$ 1.3975	$ 1.3675

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

Consolidated Balance Sheets

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

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

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

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

Consolidated Statements of Capitalization

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

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

Consolidated Statements of Changes in Stockholders' Equity

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

(A) The Company recognized a cumulative effect adjustment for its uncertain tax positions on January 1, 2007 related to the adoption of a new accounting principle.
The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

Consolidated Statements of Cash Flows

(In millions, year ended December 31)	2009	2008	2007
Cash flows from operating activities			
Net income	**$ 261.1**	$ 237.4	$ 245.2
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation and amortization	**262.6**	217.5	195.3
Impairment of assets	**3.1**	0.4	0.5
Deferred income taxes and investment tax credits, net	**269.8**	123.4	16.1
Allowance for equity funds used during construction	**(15.1)**	–	–
Loss on disposition and abandonment of assets	**1.3**	0.3	3.7
Write-down of regulatory assets	**–**	9.2	–
Stock-based compensation expense	**5.8**	4.3	3.6
Excess tax benefit on stock-based compensation	**(3.3)**	(1.9)	(2.8)
Stock-based compensation converted to cash for tax withholding	**(1.7)**	–	–
Price risk management assets	**27.8**	(25.9)	32.0
Price risk management liabilities	**(88.7)**	126.9	(74.3)
Other assets	**15.4**	5.1	(24.8)
Other liabilities	**(55.2)**	(22.9)	(61.5)
Change in certain current assets and liabilities			
Funds on deposit	**–**	–	32.0
Accounts receivable, net	**(3.3)**	46.3	9.9
Accrued unbilled revenues	**(10.2)**	(1.3)	(6.0)
Income taxes receivable	**(157.7)**	–	–
Fuel, materials and supplies inventories	**(36.1)**	(15.2)	(21.3)
Gas imbalance assets	**3.0**	0.5	(3.9)
Fuel clause under recoveries	**23.7**	3.3	(27.3)
Other current assets	**(1.4)**	(2.2)	5.4
Accounts payable	**(17.2)**	(119.6)	104.3
Customer deposits	**6.6**	3.3	2.1
Accrued taxes	**11.2**	(9.0)	(13.5)
Accrued interest	**11.9**	11.7	(7.0)
Accrued compensation	**4.9**	(8.7)	7.9
Gas imbalance liabilities	**(12.9)**	13.8	–
Fuel clause over recoveries	**178.9**	4.4	(92.1)
Other current liabilities	**(29.8)**	23.9	5.0
Net cash provided from operating activities	**654.4**	625.0	328.5
Cash flows from investing activities			
Capital expenditures (less allowance for equity funds used during construction)	**(847.8)**	(1,184.5)	(557.7)
Construction reimbursement	**38.8**	–	–
Proceeds from sale of assets	**1.4**	0.8	1.4
Capital contribution to unconsolidated affiliate	**(0.9)**	(0.3)	–
Other investing activities	**–**	(0.1)	–
Net cash used in investing activities	**(808.5)**	(1,184.1)	(556.3)
Cash flows from financing activities			
Proceeds from long-term debt	**444.8**	743.0	–
Proceeds from line of credit	**80.0**	145.0	–
Issuance of common stock	**79.6**	36.4	8.2
Excess tax benefit on stock-based compensation	**3.3**	1.9	2.8
Contributions from noncontrolling interest partner	**–**	0.5	9.7
Retirement of long-term debt	**(110.8)**	(51.1)	(3.1)
(Decrease) increase in short-term debt, net	**(123.0)**	2.2	295.8
Dividends paid on common stock	**(136.2)**	(128.2)	(124.7)
Repayment of line of credit	**(200.0)**	(25.0)	–
Net cash provided from financing activities	**37.7**	724.7	188.7
Net (decrease) increase in cash and cash equivalents	**(116.3)**	165.6	(39.1)
Cash and cash equivalents at beginning of period	**174.4**	8.8	47.9
Cash and cash equivalents at end of period	**$ 58.1**	$ 174.4	$ 8.8

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

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Organization

OGE Energy Corp. ("OGE Energy" and collectively, with its subsidiaries, the "Company") is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through four business segments: (i) electric utility, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. All significant intercompany transactions have been eliminated in consolidation.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through Oklahoma Gas and Electric Company ("OG&E") and are subject to rate regulation by the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

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

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

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

Basis of Presentation

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

Accounting Records

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Use of Estimates

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

Cash and Cash Equivalents

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

Allowance for Uncollectible Accounts Receivable

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

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

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

Fuel Inventories

OG&E

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

Enogex

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

OERI

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

Gas Imbalances

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

Property, Plant and Equipment

OG&E

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

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

(In millions, December 31)	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
2009				
McClain Plant	**77**	**$197.7**	**$55.3**	**$142.4**
Redbud Facility	**51**	**$523.3** (A)	**$80.3** (B)	**$443.0**
2008				
McClain Plant	77	$181.0	$44.6	$136.4
Redbud Facility	51	496.6 (C)	63.9 (D)	432.7

(A) *This amount includes a plant acquisition adjustment of approximately $148.3 million.*
(B) *This amount includes accumulated amortization of the plant acquisition adjustment of approximately $6.9 million.*
(C) *This amount includes a plant acquisition adjustment of approximately $153.7 million.*
(D) *This amount includes accumulated amortization of the plant acquisition adjustment of approximately $1.5 million.*

Enogex

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

OGE Energy Consolidated

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

(In millions, December 31)	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
2009			
OGE Energy (holding company and OERI)			
Holding company property, plant and equipment	**$ 107.4**	**$ 75.8**	**$ 31.6**
OERI property, plant and equipment	**7.3**	**7.0**	**0.3**
OGE Energy property, plant and equipment	**114.7**	**82.8**	**31.9**
OG&E			
Distribution assets	**2,676.2**	**861.1**	**1,815.1**
Electric generation assets	**2,878.2**	**1,141.5**	**1,736.7**
Transmission assets	**1,071.6**	**310.1**	**761.5**
Intangible plant	**29.7**	**22.6**	**7.1**
Other property and equipment	**227.9**	**80.7**	**147.2**
OG&E property, plant and equipment	**6,883.6**	**2,416.0**	**4,467.6**
Enogex			
Transportation and storage assets	**873.1**	**228.8**	**644.3**
Gathering and processing assets	**1,081.8**	**314.0**	**767.8**
Enogex property, plant and equipment	**1,954.9**	**542.8**	**1,412.1**
Total property, plant and equipment	**$8,953.2**	**$3,041.6**	**$5,911.6**
2008			
OGE Energy (holding company and OERI)			
Holding company property, plant and equipment	$ 101.4	$ 68.8	$ 32.6
OERI property, plant and equipment	7.3	7.0	0.3
OGE Energy property, plant and equipment	108.7	75.8	32.9
OG&E			
Distribution assets	2,551.5	824.8	1,726.7
Electric generation assets	2,623.8	1,095.4	1,528.4
Transmission assets	846.1	299.8	546.3
Intangible plant	26.8	18.4	8.4
Other property and equipment	222.0	76.3	145.7
OG&E property, plant and equipment	6,270.2	2,314.7	3,955.5
Enogex			
Transportation and storage assets	822.0	208.6	613.4
Gathering and processing assets	920.5	272.5	648.0
Enogex property, plant and equipment	1,742.5	481.1	1,261.4
Total property, plant and equipment	$8,121.4	$2,871.6	$5,249.8

Depreciation and Amortization

OG&E

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

Enogex

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

Asset Retirement Obligations

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

Impairment of Assets

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

Allowance for Funds Used During Construction

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

Collection of Sales Tax

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

Revenue Recognition

OG&E

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

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

Enogex

Operating revenues for gathering, processing, transportation and storage services for Enogex are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Operating revenues associated with the production of natural gas liquids ("NGLs") are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated operating revenues are reflected in Accounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income. Enogex's key natural gas producer customers in 2009 included Chesapeake Energy Marketing Inc., Devon Gas Services, L.P., Apache Corporation, BP America Production Company and Samson Resources Company. During 2009, these five customers accounted for approximately 18.6 percent, 13.2 percent, 12.7 percent, 4.0 percent and 3.9 percent, respectively, of Enogex's gathering and processing volumes. During 2009, Enogex's top 10 natural gas producer customers accounted for approximately 66.6 percent of Enogex's gathering and processing volumes.

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

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

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

OERI

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

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

Fuel Adjustment Clauses

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

Accrued Vacation

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

Accumulated Other Comprehensive Income (Loss)

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

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

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

Defined Benefit Pension and Restoration of Retirement Income and Postretirement Plans

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

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

Environmental Costs

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

Reclassifications

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

2. Accounting Pronouncements

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

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

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

3. Fair Value Measurements

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

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

(A) *Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of approximately $4.0 million, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.*

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

(B) *Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of approximately $11.8 million, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.*

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

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

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

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

Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that observable inputs are not available. Unobservable inputs shall reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk). Unobservable inputs shall be developed based on the best information available in the circumstances, which might include the reporting entity's own data. The reporting entity's own data used to develop unobservable inputs shall be adjusted if information is reasonably available that indicates that market participants would use different assumptions. Examples of instruments that may be classified as Level 3 include energy commodity purchase or sales transactions of a longer duration or in an inactive market or the valuation of ARO's such that there are no closely related markets in which quoted prices are available.

The Company utilizes either NYMEX published market prices, independent broker pricing data or broker/dealer valuations in determining the fair value of its derivative positions. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related, active market. Otherwise, they are considered Level 3.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services ("Standard & Poor's") and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

The following table is a reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at:

(In millions, December 31)	2009	2008
Assets		
Gross derivative assets	**$71.3**	$243.7
Less: amounts held in clearing broker accounts reflected in other current assets	**17.3**	86.3
Less: amounts offset under master netting agreements	**47.9**	65.4
Less: net collateral payments received from counterparties	**–**	58.1
Net price risk management assets	**$ 6.1**	$ 33.9
Liabilities		
Gross derivative liabilities	**$77.8**	$141.8
Less: amounts held in clearing broker accounts reflected in other current assets	**15.6**	70.3
Less: amounts offset under master netting agreements	**47.9**	65.4
Net price risk management liabilities	**$14.3**	$ 6.1

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

(In millions, year ended December 31)	2009	2008
Derivative assets		
Balance at January 1	**$121.2**	$ 1.4
Total gains or losses (realized/unrealized)		
Included in earnings	**–**	–
Included in other comprehensive income	**(54.0)**	2.4
Purchases, sales, issuances and settlements, net[(A)]	**(18.2)**	82.0
Transfers in and/or out of Level 3[(B)]	**–**	35.4
Balance at December 31	**$ 49.0**	$121.2
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets held at December 31	**$ –**	$ –
Derivative liabilities		
Balance at January 1	**$ –**	$ –
Total gains or losses (realized/unrealized)		
Included in earnings	**–**	–
Included in other comprehensive income	**14.7**	–
Purchases, sales, issuances and settlements, net	**–**	–
Transfers in and/or out of Level 3	**–**	–
Balance at December 31	**$ 14.7**	$ –
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to liabilities held at December 31	**$ –**	$ –

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

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

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

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

	2009		2008	
(In millions, December 31)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price risk management assets				
Energy derivative contracts	**$ 6.1**	**$ 6.1**	$ 33.9	$ 33.9
Price risk management liabilities				
Energy derivative contracts	**$ 14.3**	**$ 14.3**	$ 6.1	$ 6.1
Long-term debt				
OG&E senior notes	**$1,406.4**	**$1,492.1**	$1,406.1	$1,327.4
OG&E Energy senior notes	**99.5**	**102.6**	99.5	93.4
OG&E industrial authority bonds	**135.4**	**135.4**	135.3	135.3
Enogex senior notes	**736.8**	**746.7**	400.9	436.1
Enogex revolving credit agreement	**–**	**–**	120.0	120.0

The carrying value of the financial instruments on the Consolidated Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company's hedging and energy derivative contracts was determined generally based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties. The fair value of the Company's long-term debt is based on quoted market prices and management's estimate of current rates available for similar issues with similar maturities.

4. Stock-Based Compensation

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

The Company recorded compensation expense of approximately $5.8 million pre-tax ($3.6 million after tax, or $0.04 per basic and diluted share), $4.3 million pre-tax ($2.7 million after tax, or $0.03 per basic and diluted share) and $3.8 million pre-tax ($2.3 million after tax, or $0.03 per basic and diluted share) in 2009, 2008 and 2007, respectively, related to the Company's share-based payments. Also, during 2009, the Company converted 171,670 performance units based on a payout ratio of 135.31 percent of the target number of performance units granted in February 2006, which were settled in the Company's common stock.

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

Performance Units

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

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

Performance Units – Total Shareholder Return

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

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

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

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

(A) One performance unit = one share of the Company's common stock.

(B) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

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

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

(C) *Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.*

(D) *Of the 467,470 performance units not vested at December 31, 2009, 405,987 performance units are assumed to vest at the end of the applicable vesting period.*

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

Performance Units – Earnings Per Share

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

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

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

(A) *One performance unit = one share of the Company's common stock*

(B) *Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.*

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

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

(C) *Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.*

(D) *Of the 155,807 performance units not vested at December 31, 2009, 135,312 performance units are assumed to vest at the end of the applicable vesting period.*

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

Stock Options

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

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

Restricted Stock

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

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

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

5. Derivative Instruments and Hedging Activities

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

Commodity Price Risk

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

- NGLs put options and NGLs swaps are used to manage Enogex's NGLs exposure associated with its processing agreements;
- Natural gas swaps are used to manage Enogex's keep-whole natural gas exposure associated with its processing agreements and Enogex's natural gas exposure associated with operating its gathering, transportation and storage assets;
- Natural gas futures and swaps and natural gas commodity purchases and sales are used to manage OERI's natural gas exposure associated with its storage and transportation contracts; and
- Natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage OERI's marketing and trading activities.

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

The Company recognizes its non-exchange traded derivative instruments as PRM assets or liabilities in the Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Consolidated Balance Sheets.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable debt, treasury lock agreements and commercial paper. The Company from time to time uses treasury lock agreements to manage its interest rate risk exposure on new debt issuances. Additionally, the Company manages its interest rate exposure by limiting its variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce interest expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Credit Risk

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

Cash Flow Hedges

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

At December 31, 2009 and 2008, the Company had no outstanding treasury lock agreements that were designated as cash flow hedges.

The Company designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's contractual long/short positions and operational storage natural gas, keep-whole natural gas and NGLs hedges. Enogex's cash flow hedging activity at December 31, 2009 covers the period from January 1, 2010 through 2011. The Company also designates certain derivatives used to manage commodity exposure for certain transportation and natural gas inventory positions at OERI. OERI's cash flow hedging activity at December 31, 2009 does not extend beyond the first quarter of 2010. At December 31, 2009, the Company had the following outstanding commodity derivative instruments that were designated as cash flow hedges.

(Volumes in millions)	Commodity	Notional Volume [A]	Maturity
Short financial swaps/futures (fixed)	NGLs	0.5	Current
Purchased financial options	NGLs	1.3	Current
Purchased financial options	NGLs	1.3	Non-Current
Total purchased financial options		2.6	
Long financial swaps/futures (fixed)	Natural Gas	6.3	Current
Long financial swaps/futures (fixed)	Natural Gas	5.2	Non-Current
Total long financial swaps/ futures (fixed)		11.5	
Short financial swaps/futures (fixed)	Natural Gas	4.0	Current
Short financial basis swaps	Natural Gas	4.0	Current

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

Fair Value Hedges

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

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

Derivatives Not Designated As Hedging Instruments

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

At December 31, 2009, the Company had the following outstanding commodity derivative instruments that were not designated as either a cash flow or fair value hedge.

(Volumes in millions)	Commodity	Notional Volume [A]	Maturity
Short financial swaps/futures (fixed)	NGLs	0.8	Current
Long financial swaps/futures (fixed)	NGLs	0.8	Current
Physical purchases [B]	Natural Gas	16.1	Current
Physical purchases [B]	Natural Gas	4.1	Non-Current
Total physical purchases		20.2	
Physical sales [B]	Natural Gas	31.3	Current
Physical sales [B]	Natural Gas	13.2	Non-Current
Total physical sales		44.5	
Long financial swaps/futures (fixed)	Natural Gas	31.3	Current
Long financial swaps/futures (fixed)	Natural Gas	1.0	Non-Current
Total long financial swaps/ futures (fixed)		32.3	
Short financial swaps/futures (fixed)	Natural Gas	31.8	Current
Short financial swaps/futures (fixed)	Natural Gas	2.9	Non-Current
Total short financial swaps/ futures (fixed)		34.7	
Purchased financial option	Natural Gas	9.5	Current
Sold financial option	Natural Gas	12.8	Current
Long financial basis swaps	Natural Gas	7.7	Current
Long financial basis swaps	Natural Gas	1.0	Non-Current
Total long financial basis swaps		8.7	
Short financial basis swaps	Natural Gas	7.0	Current
Short financial basis swaps	Natural Gas	1.2	Non-Current
Total short financial basis swaps		8.2	

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

(B) Of the natural gas physical purchases and sales volumes not designated as cash flow or fair value hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.

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

(Dollars in millions) Instrument	Commodity	Balance Sheet Location	Fair Value Assets	Fair Value Liabilities
Derivatives designated as hedging instruments				
Financial options	NGLs	Current PRM	$16.4	$ –
		Non-Current PRM	23.4	–
Financial futures/swaps	NGLs	Current PRM	–	6.1
Financial futures/swaps	Natural Gas	Current PRM	–	14.8
		Non-Current PRM	–	19.7
		Other Current Assets	4.6	1.2
Total gross derivatives designated as hedging instruments			$44.4	$41.8
Derivatives not designated as hedging instruments				
Financial futures/swaps[(A)]	NGLs	Current PRM	$ 9.2	$ 8.6
Financial futures/swaps[(B)]	Natural Gas	Current PRM	3.6	12.3
		Non-Current PRM	–	0.1
		Other Current Assets	11.8	13.6
Physical purchases/sales	Natural Gas	Current PRM	0.8	0.6
		Non-Current PRM	0.6	–
Financial options	Natural Gas	Other Current Assets	0.9	0.8
Total gross derivatives not designated as hedging instruments			$26.9	$36.0
Total gross derivatives[(C)]			$71.3	$77.8

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

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

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

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Service ("Moody's") or Standard & Poor's were to lower the Company's senior unsecured debt rating to a below investment grade rating, at December 31, 2009, the Company would have been required to post approximately $11.8 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2009. In addition, the Company could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

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

(Dollars in millions)	Amount of Gain or Loss Recognized in OCI on Derivative (Effective Portion)[(A)]	Location of Gain or Loss Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Gain or Loss Reclassified from Accumulated OCI into Income (Effective Portion)	Location of Gain or Loss Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain or Loss Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
Derivatives in cash flow hedging relationships					
NGLs financial options	$ (56.4)	Operating Revenues	$ 1.7	Operating Revenues	$ –
NGLs financial futures/swaps	(33.7)	Operating Revenues	12.6	Operating Revenues	–
Natural gas financial futures/swaps	(19.8)	Operating Revenues	(26.5)	Operating Revenues	(0.2)
Total	$(109.9)	Total	$(12.2)	Total	$(0.2)

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

(Dollars in millions)	Location of Gain or Loss Recognized in Income on Derivative	Amount of Gain or Loss Recognized in Income of Derivative
Derivatives not designated as hedging instruments		
Natural gas physical purchases/sales	Operating Revenues	$(24.3)
Natural gas financial futures/swaps	Operating Revenues	17.7
NGLs financial futures/swaps	Operating Revenues	(0.2)
Total		$ (6.8)

Contracts with Master Netting Arrangements

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

6. Supplemental Cash Flow Information

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

(In millions, year ended December 31)	2009	2008	2007
Non-cash investing and financing activities			
OU Spirit future installment payments to developer	**$ 3.9**	$ –	$ –
Power plant long-term service agreement	**–**	3.5	0.7
Capital lease for distribution equipment	**–**	0.3	–
Supplemental cash flow information			
Cash paid during the period for			
Interest (net of interest capitalized of $14.7, $7.6, $4.9)	**$125.8**	$122.3	$93.5
Income taxes (net of income tax refunds)	**2.0**	–	86.6

7. Income Taxes

The items comprising income tax expense are as follows:

(In millions, year ended December 31)	2009	2008	2007
Provision (benefit) for current income taxes			
Federal	**$(147.0)**	$ (18.6)	$ 96.0
State	**(3.1)**	(0.8)	3.9
Total provision (benefit) for current income taxes	**(150.1)**	(19.4)	99.9
Provision for deferred income taxes, net			
Federal	**259.5**	126.9	18.2
State	**5.3**	1.2	2.7
Total provision for deferred income taxes, net	**264.8**	128.1	20.9
Deferred federal investment tax credits, net	**(4.2)**	(4.6)	(4.8)
Income taxes relating to other income and deductions	**10.6**	(2.9)	0.7
Total income tax expense	**$ 121.1**	$101.2	$116.7

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

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

[A] *These are credits associated with the production from OG&E's wind farms.*

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

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

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

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

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

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

8. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

In November 2008, the Company filed a Form S-3 Registration Statement to register 5,000,000 shares of the Company's common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan ("DRIP/DSPP"). The Company issued 2,007,256 shares of common stock under its DRIP/DSPP in 2009 and received proceeds of approximately $49.5 million. The Company may, from time to time, issue additional shares under its DRIP/DSPP to fund capital requirements or working capital needs.

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

Equity Issuances

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

Shareowners Rights Plan

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

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

Earnings Per Share

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

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

9. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2009, the Company was in compliance with all of its debt agreements.

OG&E has three series of variable-rate industrial authority bonds (the "Bonds") with optional redemption provisions that allow the holders to request repayment of the Bonds at various dates prior to the maturity. The Bonds, which can be tendered at the option of the holder during the next 12 months, are as follows (dollars in millions):

Series	Date Due	Amount
0.30% – 1.00%	Garfield Industrial Authority, January 1, 2025	$ 47.0
0.42% – 0.74%	Muskogee Industrial Authority, January 1, 2025	32.4
0.42% – 0.75%	Muskogee Industrial Authority, June 1, 2027	56.0
Total (redeemable during next 12 months)		$135.4

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

Long-Term Debt Maturities

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

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

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

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

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

10. Short-Term Debt

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was approximately $175.0 million and $298.0 million at December 31, 2009 and 2008, respectively, at a weighted-average interest rate of 0.27 percent and 0.75 percent, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at December 31, 2009.

(In millions)	Aggregate Commitment	Amount Outstanding [A]	Weighted-Average Interest Rate	Maturity
Revolving credit agreements and available cash				
OGE Energy[B]	$ 596.0	$175.0	0.27%[D]	12/6/12
OG&E[C]	389.0	10.2	0.14%[D]	12/6/12
Enogex[E]	250.0	–	–%[D]	3/31/13
	1,235.0	185.2	0.26%	
Cash	58.1	N/A	N/A	N/A
Total	$1,293.1	$185.2	0.26%	

(A) *Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 31, 2009.*

(B) *This bank facility is available to back up OGE Energy's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At December 31, 2009, there were no outstanding borrowings under this revolving credit agreement and approximately $175.0 million in outstanding commercial paper borrowings.*

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

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

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

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

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

11. Retirement Plans and Postretirement Benefit Plans

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

Defined Benefit Pension Plan

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

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

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

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

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

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

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

Option 2: Elect not to participate in or, for those currently participating, freeze the current cash balance benefit under the Pension Plan at December 31, 2009 so that it will only accrue annual interest credits in the future, and, for each pay period beginning on or after January 1, 2010, the Company will also contribute to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

Employees hired or rehired on or after December 1, 2009, will only be eligible to participate in the 401(k) Plan where, for each pay period, the Company will contribute to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

It is the Company's policy to fund the Pension Plan on a current basis based on the net periodic pension expense as determined by the Company's actuarial consultants. The Company could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future. During each of 2009 and 2008, the Company made contributions to its Pension Plan of approximately $50.0 million to help ensure that the Pension Plan maintains an adequate funded status. Such contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. In August 2006, legislation was passed that changed the funding requirement for single- and multi-employer defined benefit pension plans as discussed below. During 2010, the Company may contribute up to $50.0 million to its Pension Plan. The expected contribution to the Pension Plan during 2010 would be a discretionary contribution, anticipated to be in the form of cash, and is not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

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

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

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

(In millions)	OG&E [A]	Enogex	OGE Energy	Total
Pension settlement charge:				
2007	$13.3	$0.5	$2.9	$16.7
Retirement restoration plan settlement charge:				
2007	$ 0.1	–	$2.2	$ 2.3

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

Pension Plan Costs and Assumptions

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the "Pension Protection Act") into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Many of the changes enacted as part of the Pension Protection Act were required to be implemented as of the first plan year beginning in 2008. In accordance with the Pension Protection Act, the Company implemented the following changes to its Pension Plan and its 401(k) Plan, as applicable: (i) effective January 1, 2007, the Company's Pension Plan and 401(k) Plan were amended to incorporate clarifying provisions and changes relating to the Pension Protection Act notice requirements, (ii) effective January 1, 2007, the Company's Pension Plan and 401(k) Plan were amended to allow a non-spouse beneficiary to directly rollover an eligible distribution to an eligible individual retirement account, (iii) effective January 1, 2008, the Company's 401(k) Plan was amended to provide 100 percent vesting after completing three years of service, (iv) for the Company's 401(k) Plan, effective January 18, 2008, that plan was amended to implement an eligible automatic contribution arrangement and provide for a qualified default investment alternative consistent with the U.S. Department of Labor regulations, (v) effective January 1, 2008, terminated vested benefits, as defined in the Pension Plan, are payable to participants who, on or after January 1, 2008, leave the Company prior to retirement with at least three years of vesting service. Participants terminating before completing three years of vesting service and attaining age 65 will not receive a benefit, (vi) effective January 1, 2008, the Company's Pension Plan was amended to incorporate funding-based limitations which restrict, among other things, benefit accruals and the forms in which benefits may be paid if the Pension Plan's funding level falls below certain levels set by the Pension Protection Act and (vii) effective January 18, 2008, the 401(k) Plan was amended so that a participant may elect, in accordance with the 401(k) Plan procedures, to have his or her salary deferral rate to be made in the future automatically increased annually on a date and in an amount as specified by the participant in such election. The Company has taken steps to ensure that its plans, as well as participants and outside administrators, are aware of the changes.

Plan Investments, Policies and Strategies

The Pension Plan assets are held in a trust which follows an investment policy and strategy designed to maximize the long-term investment returns of the trust at prudent risk levels. Common stocks are used as a hedge against moderate inflationary conditions, as well as for participation in normal economic times. Fixed income investments are utilized for high current income and as a hedge against deflation. The Company has retained an investment consultant responsible for the general investment oversight, analysis, monitoring investment guideline compliance and providing quarterly reports to certain of the Company's members and the Company's Investment Committee (the "Investment Committee").

The various investment managers used by the trust operate within the general operating objectives as established in the investment policy and within the specific guidelines established for their respective portfolio. The table below shows the target asset allocation percentages for each major category of Pension Plan assets:

Asset Class	Target Allocation	Minimum	Maximum
Domestic all-cap equity	20%	–%	25%
Domestic equity passive	10%	–%	60%
Domestic mid-cap equity	10%	–%	10%
Domestic small-cap equity	10%	–%	10%
International equity	15%	–%	15%
Fixed income domestic	35%	30%	70%

The portfolio is rebalanced on an annual basis to bring the asset allocations of various managers in line with the target asset allocation listed above. More frequent rebalancing may occur if there are dramatic price movements in the financial markets which may cause the trust's exposure to any asset class to exceed or fall below the established allowable guidelines.

To evaluate the progress of the portfolio, investment performance is reviewed quarterly. It is, however, expected that performance goals will be met over a full market cycle, normally defined as a three to five year period. Analysis of performance is within the context of the prevailing investment environment and the advisors' investment style. The goal of the trust is to provide a rate of return consistently from three to five percent over the rate of inflation (as measured by the national Consumer Price Index) on a fee adjusted basis over a typical market cycle of no less than three years and no more than five years. Each investment manager is expected to outperform its respective benchmark. Below is a list of each asset class utilized with appropriate comparative benchmark(s) each manager is evaluated against:

Asset Class	Comparative Benchmark(s)
Fixed income	Barclays Capital Aggregate Index
Equity index	S&P 500 Index
Value equity	Russell 1000 Value Index – Short-term S&P 500 Index – Long-term
Growth equity	Russell 1000 Growth Index – Short-term S&P 500 Index – Long-term
Mid-cap equity	S&P 400 Midcap Index
Small-cap equity	Russell 2000 Index
International equity	Morgan Stanley Capital International Europe, Australia and Far East Index

The fixed income manager is expected to use discretion over the asset mix of the trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies, or its instrumentalities (which have no limits) is limited to five percent of the fixed income portfolio as measured by market value. At least 75 percent of the invested assets must possess an investment grade rating at or above Baa3 or BBB- by Moody's, Standard & Poor's or Fitch Ratings ("Fitch"). The portfolio may invest up to 10 percent of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. The purchase of any of the Company's equity, debt or other securities is prohibited.

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The domestic mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the S&P 400 Midcap Index, small dividend yield, return on equity at or near the S&P 400 Midcap Index and earnings per share growth rate at or near the S&P 400 Midcap Index. The domestic small-cap equity manager will purchase shares of companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and earnings per share growth rate at or near the Russell 2000. The international global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall trust across the global equity markets. The manager is required to operate under certain restrictions including: regional constraints, diversification requirements and percentage of U.S. securities. The Morgan Stanley Capital International Europe, Australia and the Far East Index ("EAFE") is the benchmark for comparative performance purposes. The EAFE Index is a market value weighted index comprised of over 1,000 companies traded on the stock markets of Europe, Australia, New Zealand and the Far East. All of the equities which are purchased for the international portfolio are thoroughly researched. Only companies with a market capitalization in excess of $100 million are allowable. No more than five percent of the portfolio can be invested in any one stock at the time of purchase. All securities are freely traded on a recognized stock exchange and there are no 144-A securities and no over-the-counter derivatives. The following investment categories are excluded: options (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares).

For all domestic equity investment managers, no more than eight percent (five percent for mid-cap and small-cap equity managers) can be invested in any one stock at the time of purchase and no more than 16 percent (10 percent for mid-cap and small-cap equity managers) after accounting for price appreciation. A minimum of 95 percent of the total assets of an equity manager's portfolio must be allocated to the equity markets. Options or financial futures may not be purchased unless prior approval of the Investment Committee is received. The purchase of securities on margin is prohibited as is securities lending. Private placement or venture capital may not be purchased. All interest and dividend payments must be swept on a daily basis into a short-term money market fund for re-deployment. The purchase of any of the Company's equity, debt or other securities is prohibited. The purchase of equity or debt issues of the portfolio manager's organization is also prohibited. The aggregate positions in any company may not exceed one percent of the fair market value of its outstanding stock.

Plan Assets

The following table is a summary of the Pension Plan's assets that are measured at fair value on a recurring basis at December 31, 2009. There were no Level 3 investments held by the Pension Plan at December 31, 2009.

(In millions)	Total	Level 1	Level 2
Common stocks			
U.S. common stocks	$152.4	$152.4	$ –
Foreign common stocks	57.2	57.2	–
Bonds, debentures and notes[A]			
Bonds, debentures and notes	119.1	–	119.1
Mortgage-backed securities	8.6	–	8.6
U.S. Government obligations			
Mortgage-backed securities	72.3	–	72.3
U.S. treasury notes and bonds[B]	22.2	22.2	–
Other securities	4.5	–	4.5
Commingled fund[C]	32.8	–	32.8
Common collective trust[D]	15.9	–	15.9
Foreign government bonds	5.1	–	5.1
U.S. municipal bonds	2.5	–	2.5
Foreign mutual funds	2.0	2.0	–
Foreign preferred stock	0.9	0.9	–
U.S. mutual funds	0.8	0.8	–
Total	$496.3	$235.5	$260.8

(A) *This category primarily represents U.S. corporate bonds with an investment grade rating at or above Baa3 or BBB- by Moody's, Standard & Poor's or Fitch.*

(B) *This category represents U.S. treasury notes and bonds with a Moody's rating of Aaa and Government Agency Bonds with a Moody's rating of A1 or higher.*

(C) *This category represents units of participation in a commingled fund that primarily invest in stocks and bonds of U.S. companies.*

(D) *This category represents units of participation in an investment pool which primarily invests in commercial paper, repurchase agreements and U.S. treasury notes and bonds and certificates of deposit.*

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

Level 1 inputs are quoted prices in active markets for identical assets or liabilities that the Pension Plan and postretirement benefit plans have the ability to access at the measurement date. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs include the following: (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in markets that are not active, (iii) inputs other than quoted prices that are observable for the asset or liability or (iv) inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that observable inputs are not available. Unobservable inputs shall reflect the Pension Plan's and postretirement benefit plans own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk). Unobservable inputs shall be developed based on the best information available in the circumstances, which might include the Pension Plan's and postretirement benefit plans own data. The Pension Plan's and postretirement benefit plans own data used to develop unobservable inputs shall be adjusted if information is reasonably available that indicates that market participants would use different assumptions.

Restoration of Retirement Income Plan

The Company provides a restoration of retirement income plan to those participants in the Company's Pension Plan whose benefits are subject to certain limitations under the Internal Revenue Code (the "Code"). The benefits payable under this restoration of retirement income plan are equivalent to the amounts that would have been payable under the Pension Plan but for these limitations. The restoration of retirement income plan is intended to be an unfunded plan.

The Company expects to pay benefits related to its Pension Plan and restoration of retirement income plan of approximately $47.9 million in 2010, $58.3 million in 2011, $74.4 million in 2012, $73.3 million in 2013, $72.7 million in 2014 and an aggregate of $297.7 million in years 2015 to 2019. These expected benefits are based on the same assumptions used to measure the Company's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members ("postretirement benefits"). Regular, full-time, active employees hired prior to February 1, 2000 whose age and years of credited service total or exceed 80 or have attained age 55 with 10 years of vesting service at the time of retirement are entitled to postretirement medical benefits while employees hired on or after February 1, 2000, are not entitled to postretirement medical benefits. Prior to January 1, 2008, all regular, full-time, active employees whose age and years of credited service total or exceed 80 or have attained age 55 with five years of vesting service at the time of retirement are entitled to postretirement life insurance benefits. Effective January 1, 2008, all regular, full-time, active employees whose age and years of credited service total or exceed 80 or have attained age 55 with three years of vesting service at the time of retirement are entitled to postretirement life insurance benefits. Eligible retirees must contribute such amount as the Company specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. OG&E charges to expense the postretirement benefit costs and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

Plan Assets

The following table is a summary of the postretirement benefit plans' assets that are measured at fair value on a recurring basis at December 31, 2009. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2009.

(In millions)	Total	Level 1	Level 3
Group retiree medical insurance contract[A]	$49.3	$ –	$49.3
U.S. mutual fund[B]	4.9	4.9	–
Cash	0.8	0.8	–
Total	$55.0	$5.7	$49.3

(A) *This category represents a group retiree medical insurance contract which invests in a pool of mutual funds, bonds and money market accounts, of which a significant portion is comprised of mortgage-backed securities.*

(B) *This category represents investments in a U.S. equity mutual fund.*

The postretirement benefit plans Level 3 investment includes an investment in a group retiree medical insurance contract. The unobservable input included in the valuation of the contract includes the approach for determining the allocation of the postretirement benefit plans pro-rata share of the total assets in the contract.

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

(In millions, year ended December 31)	2009
Group retiree medical insurance contract	
Balance at January 1	**$55.1**
Actual return on plan assets relating to assets held at the reporting date	**(5.8)**
Purchases, sales, issuances and settlements, net	**–**
Transfers in and/or out of Level 3	**–**
Balance at December 31	**$49.3**

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

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

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. Future health care cost trend rates are assumed to be 9.49 percent in 2010 with the rates trending downward to five percent by 2018. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

(In millions, year ended December 31)	2009	2008	2007
One-percentage point increase			
Effect on aggregate of the service and interest cost components	**$ 2.4**	$ 2.2	$ 2.3
Effect on accumulated postretirement benefit obligations	**40.3**	28.3	26.9
One-percentage point decrease			
Effect on aggregate of the service and interest cost components	**$ 1.9**	$ 1.8	$ 1.9
Effect on accumulated postretirement benefit obligations	**32.9**	23.4	22.2

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Medicare Act"). The Medicare Act expanded Medicare to include, for the first time, coverage for prescription drugs. Management expects that the accumulated postretirement benefit obligation ("APBO") for the Company with respect to its postretirement medical plan will be reduced by approximately $50.3 million as a result of savings to the Company resulting from the Medicare Act provided subsidy, which will reduce the Company's costs for its postretirement medical plan by approximately $6.8 million annually. The $6.8 million in annual savings is comprised of a reduction of approximately $3.2 million from amortization of the $50.3 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $3.1 million and a reduction in the service cost due to the subsidy of approximately $0.5 million.

The Company expects to pay gross benefits payments related to its postretirement benefit plans, including prescription drug benefits, of approximately $12.8 million in 2010, $14.1 million in 2011, $15.4 million in 2012, $16.9 million in 2013, $18.4 million in 2014 and an aggregate of $109.5 million in years 2015 to 2019. Based on the current law, the Company expects to receive Federal subsidy receipts provided by the Medicare Act of approximately $1.7 million in 2010, $1.9 million in 2011, $2.1 million in 2012, $2.4 million in 2013, $2.6 million in 2014 and an aggregate of $16.6 million in years 2015 to 2019. The Company received approximately $1.5 million in Federal subsidy receipts in 2009.

Obligations and Funded Status

The following table presents the status of the Company's Pension Plan, the restoration of retirement income plan and the postretirement benefit plans for 2009 and 2008. The benefit obligation for the Company's Pension Plan and the restoration of retirement income plan represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated postretirement benefit obligation. The accumulated postretirement benefit obligation for the Company's Pension Plan and restoration of retirement income plan differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated benefit obligation for the Pension Plan and the restoration of retirement income plan at December 31, 2009 was approximately $558.3 million and $6.4 million, respectively. The accumulated benefit obligation for the Pension Plan and the restoration of retirement income plan at December 31, 2008 was approximately $485.1 million and $4.8 million, respectively. The details of the funded status of the Pension Plan, the restoration of retirement income plan and the postretirement benefit plans and the amounts included in the Consolidated Balance Sheets are as follows:

	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions, December 31)	2009	2008	2009	2008	2009	2008
Change in benefit obligation						
Beginning obligations	**$(547.0)**	$(518.0)	**$(7.3)**	$(4.0)	**$(234.3)**	$(216.8)
Service cost	**(18.1)**	(19.0)	**(0.7)**	(0.7)	**(3.3)**	(3.7)
Interest cost	**(31.4)**	(31.4)	**(0.4)**	(0.4)	**(14.1)**	(13.4)
Plan amendments	**(10.2)**	–	**(0.5)**	–	**–**	–
Plan curtailments	**0.4**	–	**–**	–	**–**	–
Participants' contributions	**–**	–	**–**	–	**(6.8)**	(6.0)
Actuarial gains (losses)	**(39.3)**	(19.5)	**0.1**	(2.7)	**(45.2)**	(9.2)
Benefits paid	**34.7**	40.9	**0.5**	0.5	**15.7**	14.8
Ending obligations	**(610.9)**	(547.0)	**(8.3)**	(7.3)	**(288.0)**	(234.3)
Change in plans' assets						
Beginning fair value	**389.9**	514.2	**–**	–	**57.0**	78.5
Actual return on plans' assets	**91.1**	(133.4)	**–**	–	**(7.3)**	(19.2)
Employer contributions	**50.1**	50.0	**0.5**	0.5	**14.2**	6.5
Participants' contributions	**–**	–	**–**	–	**6.8**	6.0
Benefits paid	**(34.7)**	(40.9)	**(0.5)**	(0.5)	**(15.7)**	(14.8)
Ending fair value	**496.3**	389.9	**–**	–	**55.0**	57.0
Funded status at end of year	**$(114.6)**	$(157.1)	**$(8.3)**	$(7.3)	**$(233.0)**	$(177.3)

Net Periodic Benefit Cost

	Pension Plan			Restoration of Retirement Income Plan			Postretirement Benefit Plans		
(In millions, year ended December 31)	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Service cost	**$18.1**	$ 19.0	$ 20.6	**$0.7**	$0.8	$0.6	**$ 3.3**	$ 3.7	$ 4.0
Interest cost	**31.4**	31.4	31.8	**0.4**	0.4	0.5	**14.1**	13.4	12.4
Return on plan assets	**(33.0)**	(43.7)	(43.9)	**–**	–	–	**(6.5)**	(6.5)	(5.9)
Amortization of transition obligation	**–**	–	–	**–**	–	–	**2.7**	2.7	2.7
Amortization of net loss	**23.5**	9.3	10.5	**0.3**	0.3	0.2	**5.0**	4.0	6.1
Amortization of unrecognized prior service cost	**0.8**	0.9	5.2	**0.6**	0.6	0.6	**1.0**	1.9	2.1
Settlement	**–**	–	16.7	**–**	–	2.3	**–**	–	–
Net periodic benefit cost[(A)]	**$40.8**	$ 16.9	$ 40.9	**$2.0**	$2.1	$4.2	**$19.6**	$19.2	$21.4

(A) In addition to the approximately $42.8 million, $19.0 million and $45.1 million of net periodic benefit cost recognized in 2009, 2008 and 2007, respectively, the Company recognized the following:

- *A reduction in pension expense in 2009 of approximately $2.2 million, an increase in pension expense in 2008 of approximately $10.1 million and a reduction in pension expense in 2007 of approximately $10.1 million to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction which are identified as Deferred Pension Plan Expenses (see Note 1); and*
- *A reduction in pension expense in 2009 of approximately $3.2 million in the Arkansas jurisdiction to reflect the approval of recovery of OG&E's 2006 and 2007 pension settlement costs in the May 2009 Arkansas rate order which are identified as Deferred Pension Plan Expenses (see Note 1).*

The capitalized portion of the net periodic pension benefit cost was approximately $8.4 million, $4.0 million and $5.5 million at December 31, 2009, 2008 and 2007, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $4.1 million, $4.6 million and $4.8 million at December 31, 2009, 2008 and 2007, respectively.

Rate Assumptions

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
(Year ended December 31)	**2009**	2008	2007	**2009**	2008	2007
Discount rate	**5.30%**	6.25%	6.25%	**6.00%**	6.25%	6.25%
Rate of return on plans' assets	**8.50%**	8.50%	8.50%	**8.50%**	8.50%	8.50%
Compensation increases	**4.50%**	4.50%	4.50%	**N/A**	N/A	N/A
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**9.49%**	9.00%	9.00%
Ultimate trend rate	**N/A**	N/A	N/A	**5.00%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2018**	2014	2013

N/A – not applicable

The overall expected rate of return on plan assets assumption remained at 8.50 percent in 2008 and 2009 in determining net periodic benefit cost. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the Pension Plan or postretirement benefit plans. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans' current and expected asset allocation.

Post-Employment Benefit Plan

Disabled employees receiving benefits from the Company's Group Long-Term Disability Plan are entitled to continue participating in the Company's Medical Plan along with their dependents. The post-employment benefit obligation represents the actuarial present value of estimated future medical benefits that are attributed to employee service rendered prior to the date as of which such information is presented. The obligation also includes future medical benefits expected to be paid to current employees participating in the Company's Group Long-Term Disability Plan and their dependents, as defined in the Company's Medical Plan.

The post-employment benefit obligation is determined by an actuary on a basis similar to the accumulated postretirement benefit obligation. The estimated future medical benefits are projected to grow with expected future medical cost trend rates and are discounted for interest at the discount rate and for the probability that the participant will discontinue receiving benefits from the Company's Group Long-Term Disability Plan due to death, recovery from disability, or eligibility for retiree medical benefits. The Company's post-employment benefit obligation was approximately $2.2 million and $2.1 million at December 31, 2009 and 2008, respectively.

Defined Contribution Retirement Plan

The Company provides a 401(k) Plan. Each regular full-time employee of the Company or a participating affiliate is eligible to participate in the 401(k) Plan immediately. All other employees of the Company or a participating affiliate are eligible to become participants in the 401(k) Plan after completing one year of service as defined in the 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to the limitations of the Code. The 401(k) Plan was amended in October 2009, as discussed previously, whereby employees were offered a one-time irrevocable election to either stay in their current 401(k) Plan where the Company matching contributions are discussed below or select an option whereby, effective January 1, 2010, the Company will contribute on behalf of each participant, depending on the option selected, 200 percent of the participant's contributions up to five percent of compensation or 100 percent of the participant's contributions up to six percent of compensation. In the current 401(k) Plan, the Company contributes to the 401(k) Plan each pay period, on behalf of each participant, an amount equal to 50 percent of the participant's contributions up to six percent of compensation for participants whose employment or re-employment date occurred before February 1, 2000 and who have less than 20 years of service, as defined in the 401(k) Plan, and an amount equal to 75 percent of the participant's contributions up to six percent of compensation for participants whose employment or re-employment date occurred before February 1, 2000 and who have 20 or more years of service, as defined in the 401(k) Plan. For participants whose employment or re-employment date occurred on or after February 1, 2000 and before December 1, 2009, under the current 401(k) Plan, the Company contributes 100 percent of the participant's contributions up to six percent of compensation. For participants hired on or after December 1, 2009, the Company contributes, effective January 1, 2010, 200 percent of the participant's contributions up to five percent of compensation. No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Prior to January 1, 2010, the Company's contribution, which was initially allocated for investment to the OGE Energy Corp. Common Stock Fund, was made in shares of the Company's common stock or in cash which was used to invest in the Company's common stock. Once made, the Company's contribution could be reallocated, on any business day, by participants to other available investment options. The 401(k) Plan was amended effective January 1, 2010, whereby the Company's contribution may be directed to any available investment option in the 401(k) Plan. The Company contributed approximately $9.3 million, $8.6 million and $7.6 million in 2009, 2008 and 2007, respectively, to the 401(k) Plan.

Deferred Compensation Plan

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees' 401(k) Plan contributions as well as offering this plan to be competitive in the marketplace.

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers. The Company matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on the option the participant elected under the Choice Program discussed above, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after six years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan. In addition, the Benefits Committee may award discretionary employer contribution credits to a participant under the plan. The Company accounts for the contributions related to the Company's executive officers in this plan as Accrued Benefit Obligations and the Company accounts for the contributions related to the Company's directors in this plan as Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. The investment associated with these contributions is accounted for as Other Property and Investments in the Consolidated Balance Sheets. The appreciation of these investments is accounted for as Other Income and the increase in the liability under the plan is accounted for as Other Expense in the Consolidated Statements of Income.

Supplemental Executive Retirement Plan

The Company provides a supplemental executive retirement plan in order to attract and retain lateral hires or other executives designated by the Compensation Committee of the Company's Board of Directors who may not otherwise qualify for a sufficient level of benefits under the Company's Pension Plan and restoration of retirement income plan. The supplemental executive retirement plan is intended to be an unfunded plan and not subject to the benefit limits imposed by the Code.

12. Report of Business Segments

The Company's business is divided into four segments for financial reporting purposes. These segments are as follows: (i) electric utility, which is engaged in the generation, transmission, distribution and sale of electric energy, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. As discussed in Note 1, on January 1, 2008, Enogex distributed the stock of OERI, which engages in the marketing of natural gas, to OGE Energy and, as a result, OERI is no longer a subsidiary of Enogex. Other Operations primarily included the operations of the holding company. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. In reviewing its segment operating results, the Company focuses on operating income as its measure of segment profit and loss, and, therefore has presented this information below. The following tables summarize the results of the Company's business segments for the years ended December 31, 2009, 2008 and 2007.

(In millions)	Electric Utility	Transportation and Storage [B]	Gathering and Processing [B]	Marketing	Other Operations	Eliminations	Total
2009							
Operating revenues	**$1,751.2**	**$ 401.0**	**$ 657.5**	**$ 619.9**	**$ –**	**$ (559.9)**	**$2,869.7**
Cost of goods sold	**796.3**	**239.9**	**458.8**	**617.7**	**–**	**(555.0)**	**1,557.7**
Gross margin on revenues	**954.9**	**161.1**	**198.7**	**2.2**	**–**	**(4.9)**	**1,312.0**
Other operation and maintenance	**348.0**	**40.9**	**87.2**	**9.2**	**(13.9)**	**(4.6)**	**466.8**
Depreciation and amortization	**187.4**	**20.4**	**43.9**	**0.1**	**10.8**	**–**	**262.6**
Impairment of assets	**0.3**	**0.9**	**1.9**	**–**	**–**	**–**	**3.1**
Taxes other than income	**65.1**	**13.2**	**5.5**	**0.4**	**3.4**	**–**	**87.6**
Operating income (loss)	**$ 354.1**	**$ 85.7**	**$ 60.2**	**$ (7.5)**	**$ (0.3)**	**$ (0.3)**	**$ 491.9**
Total assets	**$5,478.1**	**$1,597.7**	**$ 866.1**	**$ 125.2**	**$2,685.4**	**$(3,485.8)**	**$7,266.7**
Capital expenditures	**$ 600.5**	**$ 71.4**	**$ 166.0**	**$ –**	**$ 10.2**	**$ (0.3)**	**$ 847.8**
2008							
Operating revenues	$1,959.5	$ 625.9	$1,053.2	$1,529.4	$ –	$(1,097.3)	$4,070.7
Cost of goods sold	1,114.9	479.7	806.4	1,509.5	–	(1,092.5)	2,818.0
Gross margin on revenues	844.6	146.2	246.8	19.9	–	(4.8)	1,252.7
Other operation and maintenance[A]	351.6	48.2	87.3	12.9	(2.0)	(5.8)	492.2
Depreciation and amortization	155.0	17.5	37.1	0.2	7.7	–	217.5
Impairment of assets	–	–	0.4	–	–	–	0.4
Taxes other than income	59.7	12.7	4.6	0.4	3.1	–	80.5
Operating income (loss)	$ 278.3	$ 67.8	$ 117.4	$ 6.4	$ (8.8)	$ 1.0	$ 462.1
Total assets	$4,851.2	$1,265.9	$ 836.9	$ 235.1	$2,469.1	$(3,139.7)	$6,518.5
Capital expenditures	$ 840.1	$ 93.3	$ 240.2	$ –	$ 12.9	$ (2.0)	$1,184.5
2007							
Operating revenues	$1,835.1	$ 529.1	$ 799.4	$1,541.2	$ –	$ (907.2)	$3,797.6
Cost of goods sold	1,025.1	396.4	603.5	1,513.4	–	(903.7)	2,634.7
Gross margin on revenues	810.0	132.7	195.9	27.8	–	(3.5)	1,162.9
Other operation and maintenance	320.7	48.5	72.1	10.1	(11.3)	(3.3)	436.8
Depreciation and amortization	141.3	17.0	28.7	0.2	8.1	–	195.3
Impairment of assets	–	0.5	–	–	–	–	0.5
Taxes other than income	56.0	11.7	3.7	0.4	3.2	–	75.0
Operating income	$ 292.0	$ 55.0	$ 91.4	$ 17.1	$ –	$ (0.2)	$ 455.3
Total assets	$3,874.9	$1,519.3	$ 931.4	$ 253.2	$2,297.6	$(3,638.6)	$5,237.8
Capital expenditures	$ 377.3	$ 49.0	$ 125.0	$ 0.2	$ 14.5	$ (8.3)	$ 557.7

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

[B] *Beginning in 2008, Enogex began bifurcating intercompany natural gas purchase and sale transactions based upon the operational sources of the natural gas versus recognizing transactions on a net basis in 2006 and 2007. As a result, certain 2006 and 2007 transactions have been reclassified within the segment disclosure for consistency of presentation. However, certain 2006 and 2007 transactions have not been reclassified as the information is not available. As a result of this reclassification, there is no impact on the Company's consolidated Operating Revenues or Cost of Goods Sold.*

13. Commitments and Contingencies

Operating Lease Obligations

The Company has operating lease obligations expiring at various dates, primarily for OG&E railcar leases and Enogex noncancellable operating leases. Future minimum payments for noncancellable operating leases are as follows:

(In millions, year ended December 31)	2010	2011	2012	2013	2014	2015 and Beyond	Total
Operating lease obligations							
OG&E railcars	$3.9	$38.0	$ –	$ –	$ –	$ –	$41.9
Enogex noncancellable operating leases	2.5	1.6	0.4	–	–	–	4.5
Total operating lease obligations	$6.4	$39.6	$0.4	$ –	$ –	$ –	$46.4

Payments for operating lease obligations were approximately $9.2 million, $7.3 million and $6.7 million in 2009, 2008 and 2007, respectively.

OG&E Railcar Lease Agreement

At December 31, 2009, OG&E had a noncancellable operating lease with purchase options, covering 1,462 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. At the end of the lease term, which is January 31, 2011, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of approximately $31.5 million.

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

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

OG&E Coal Transportation Contracts

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

OG&E also filed a complaint at the Surface Transportation Board ("STB") requesting the establishment of reasonable rates, practices and service terms for the transportation of coal from Union Pacific served mines in the southern Powder River Basin, Wyoming to OG&E's Muskogee power plant. OG&E began paying interim shipping rates, subject to refund, while this matter was pending with the STB. On July 24, 2009 the STB issued a decision awarding OG&E a reduction in interim shipping rates to its Muskogee power plant. In 2009, OG&E received a refund of approximately $7.7 million from Union Pacific related to payments OG&E made in 2009. All refund amounts are being passed through to OG&E's customers.

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

OG&E Termination of Wholesale Agreement

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

Public Utility Regulatory Policy Act of 1978

At December 31, 2009, OG&E has agreements with two qualifying cogeneration facilities ("QF") having terms of 15 to 32 years. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978 ("PURPA"). Stated generally, PURPA and the regulations thereunder promulgated by the FERC require OG&E to purchase power generated in a manufacturing process from a QF. The rate for such power to be paid by OG&E was approved by the OCC. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by OG&E; the other is a capacity charge, which OG&E must pay the QF for having the capacity available. However, if no electrical power is made available to OG&E for a period of time (generally three months), OG&E's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is recoverable in rates from customers. For the AES-Shady Point, Inc. ("AES") QF contract for 320 MWs, OG&E purchases 100 percent of the electricity generated by the QF. In addition, effective September 1, 2004, OG&E entered into a new 15-year power purchase agreement for 120 MWs with PowerSmith Cogeneration Project, L.P. ("PowerSmith") in which OG&E purchases 100 percent of electricity generated by PowerSmith.

In 2009, 2008 and 2007, OG&E made total payments to cogenerators of approximately $139.8 million, $152.8 million and $156.8 million, respectively, of which approximately $83.1 million, $84.4 million and $88.9 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as Cost of Goods Sold. The future minimum capacity payments under the contracts are approximately: 2010 – $86.1 million, 2011 – $83.1 million, 2012 – $81.1 million, 2013 – $79.0 million and 2014 – $76.7 million.

OG&E Fuel Minimum Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of approximately $358.8 million, $257.6 million and $232.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. OG&E has entered into future purchase commitments of necessary fuel supplies of approximately: 2010 – $340.0 million, 2011 – $63.1 million, 2012 – $21.1 million and 2013 – $1.8 million. OG&E also has a coal contract for purchases from January 2011 through December 2015. As the coal purchases in this contract for years 2013 through 2015 are valued based on an index price to be determined in the future, these amounts are not disclosed.

OG&E Wind Power Purchase Commitments

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

OG&E also received approval on January 5, 2010 from the OCC for two wind power purchase agreements with two wind developers who are to build two new wind farms, totaling 280 MWs, in northwestern Oklahoma. OG&E intends to add this capability to its power-generation portfolio by the end of 2010. Under the terms of the agreements, CPV Keenan is to build a 150 MW wind farm in Woodward County and Edison Mission Energy is to build a 130 MW facility in Dewey County near Taloga. The agreements are both 20-year power purchase agreements, under which the developers are to build, own and operate the wind generating facilities and OG&E will purchase their electric output. See Note 14 for a further discussion.

OG&E purchased wind power from FPL Energy of approximately $4.0 million, $4.4 million and $3.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. OG&E has entered into future wind purchase commitments of approximately: 2010 – $10.2 million, 2011 – $51.3 million, 2012 – $52.0 million, 2013 – $52.2 million, 2014 – $52.6 million and 2015 and beyond – $730.6 million.

OG&E Long-Term Service Agreements

In July 2004, OG&E acquired a 77 percent interest in the McClain Plant. As part of that acquisition, OG&E became subject to an existing long-term parts and service maintenance contract for the upkeep of the natural gas-fired combined cycle generation facility. The contract was initiated in December 1999, and runs for the earlier of 96,000 factored-fired hours or 4,800 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2015. The contract requires payments based on both a fixed and variable cost component, depending on how much the McClain Plant is used. OG&E's share of the estimated obligation under the contract, based on the projected future use of the McClain Plant, is approximately: 2010 – $1.4 million, 2011 – $15.8 million, 2012 – $1.5 million, 2013 – $1.5 million, 2014 – $17.1 million and 2015 and beyond – $1.2 million.

In September 2008, OG&E acquired a 51 percent interest in the Redbud Facility. As part of that acquisition, OG&E became subject to an existing long-term parts and service maintenance contract for the upkeep of the natural gas-fired combined cycle generation facility. The contract was initiated in January 2001, and runs for the earlier of 120,000 factored-fired hours or 4,500 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2025. The contract requires payments based on both a fixed and variable cost component, depending on how much the Redbud Facility is used. OG&E's share of the estimated obligation under the contract, based on the projected future use of the Redbud Facility, is approximately: 2010 – $2.3 million, 2011 – $0.6 million, 2012 – $10.5 million, 2013 – $11.9 million, 2014 – $7.4 million and 2015 and beyond – $70.1 million.

Natural Gas Units

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

Coal

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

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

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

Agreement with Midcontinent Express Pipeline, LLC

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

On July 25, 2008, the FERC issued its order approving the MEP project including the approval of a limited jurisdiction certificate authorizing the Enogex lease agreement with MEP denying the request for consolidation and rejecting all claims raised by protestors regarding the lease agreement. Accordingly, Enogex proceeded with the construction of facilities necessary to implement this service. On August 25, 2008, the same protestor filed a request for rehearing which the FERC denied. Enogex commenced service to MEP under the lease agreement on June 1, 2009. On July 16, 2009, the protestor filed, with the United States Court of Appeals for the District of Columbia Circuit, a petition for review of the FERC's orders approving the MEP construction and the MEP lease of capacity from Enogex requesting that such orders be modified or set aside on the grounds that they are arbitrary, capricious and contrary to law. The petitioner, the FERC and intervening parties have been given an opportunity to brief the issues. Enogex expects to participate in the filing of a joint intervenors' brief in support of the FERC's order in this matter, which final briefing is scheduled to be completed in the third quarter of 2010.

In 2009, OERI entered into an FTSA with MEP for 10,000 Dth/day of firm capacity on the pipeline. The FTSA was for a five-year term beginning with the in-service date of the MEP pipeline in June 2009 with an annual demand fee of approximately $2.1 million. OERI's demand fee obligations are estimated at approximately $2.1 million for each of the years 2010 through 2013; and $0.8 million in 2014.

Natural Gas Measurement Cases

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

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

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

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

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

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

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

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

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

Farris Buser Litigation

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

Pipeline Rupture

On November 14, 2008, a natural gas gathering pipeline owned by Enogex ruptured in Grady County, near Alex, Oklahoma, resulting in a fire that caused injuries to one resident and destroyed three residential structures. The cause of the rupture is not known and an investigation of the incident is ongoing. The damaged pipeline has been repaired and the pipeline is back in service. After the incident, Enogex coordinated and assisted the affected residents. Enogex resolved matters with two of the residents and Enogex continues to seek resolution with a remaining resident. This resident filed a legal action in May 2009 in the District Court of Cleveland County, Oklahoma, against OGE Energy and Enogex seeking to recover actual and punitive damages in excess of $10,000. The parties participated in a mediation of the pending action in August but were unable to resolve the action. Enogex has requested information regarding property and non-economic damage from the plaintiffs but has not yet received a response. Enogex intends to make full payment for actual medical expenses and property damages in this case. While the Company cannot predict the outcome of this lawsuit at this time, the Company intends to vigorously defend any demand for punitive damages or excessive compensatory damages in this case and believes that its ultimate resolution will not be material to the Company's consolidated financial position or results of operations.

Franchise Fee Lawsuit

On June 19, 2006, two OG&E customers brought a putative class action, on behalf of all similarly situated customers, in the District Court of Creek County, Oklahoma, challenging certain charges on OG&E's electric bills. The plaintiffs claim that OG&E improperly charged sales tax based on franchise fee charges paid by its customers. The plaintiffs also challenge certain franchise fee charges, contending that such fees are more than is allowed under Oklahoma law. OG&E's motion for summary judgment was denied by the trial judge. OG&E filed a writ of prohibition at the Oklahoma Supreme Court asking the court to direct the trial court to dismiss the class action suit. In January 2007, the Oklahoma Supreme Court "arrested" the District Court action until, and if, the propriety of the complaint of billing practices is determined by the OCC. In September 2008, the plaintiffs filed an application with the OCC asking the OCC to modify its order which authorized OG&E to collect the challenged franchise fee charges. On March 10, 2009, the Oklahoma Attorney General, OG&E, OG&E Shareholders Association and the Staff of the Public Utility Division of the OCC all filed briefs arguing that the application should be dismissed. On December 9, 2009 the OCC issued an order dismissing the plaintiffs' request for a modification of the OCC order which authorizes OG&E to collect and remit sales tax on franchise fee charges. In its December 9, 2009 order, the OCC advised the plaintiffs that the ruling does not address the question of whether OG&E's collection and remittance of such sales tax should be discontinued prospectively. On December 21, 2009, the plaintiffs filed a motion at the Oklahoma Supreme Court asking the court to deny OG&E's writ of prohibition and to remand the cause to the District Court. On December 29, 2009, the Oklahoma Supreme Court declared the plaintiffs' motion moot. On January 27, 2010, the OCC Staff filed a motion asking the OCC to dismiss the cause and close the cause at the OCC. If the OCC Staff's motion is granted, the plaintiffs would be required to file a new cause in order to ask for prospective relief. In its motion, the OCC Staff stated that the plaintiff's counsel advised the OCC Staff counsel that the plaintiffs have no desire to seek a determination regarding prospective relief from the OCC. It is unknown whether the plaintiffs will attempt to continue the District Court action. OG&E believes that the lawsuit is without merit.

Oxley Litigation

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

Environmental Laws and Regulations

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

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

Air

Sulfur Dioxide

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

The EPA allocated SO2 allowances to OG&E starting in 2000 and OG&E started banking allowances in 2001. OG&E sold 10,000 banked allowances in 2009 for approximately $0.8 million. Also, during 2009, OG&E received proceeds of approximately $0.1 million from the annual EPA spot (year 2009) and seven-year advance (year 2016) allowance auctions that were held in March 2009.

Nitrogen Oxides

On January 25, 2010, the EPA released a rule strengthening the National Ambient Air Quality Standards ("NAAQS") for oxides of nitrogen as measured by nitrogen dioxide ("NO2") which is effective March 26, 2011. The rule establishes a new one-hour standard and monitoring requirements, as well as an approach for implementing the new standard. Oklahoma is currently in attainment with the new standard and it is anticipated that Oklahoma will be designated "unclassifiable" in 2012 because the new monitoring requirements will not yet be fully implemented. After the new monitoring network is deployed and has collected three years of air quality data, the EPA will re-designate areas in 2016 or 2017 based on the new data. It is currently anticipated that Oklahoma will be designated "attainment" at that time.

With respect to the nitrogen oxide ("NOX") regulations of the acid rain program, OG&E committed to meeting a 0.45 lbs/MMBtu NOX emission level in 1997 on all coal-fired boilers. As a result, OG&E was eligible to exercise its option to extend the effective date of the lower emission requirements from the year 2000 until 2008. The regulations required that OG&E achieve a NOX emission level of 0.40 lbs/MMBtu for these boilers which began in 2008. OG&E's average NOX emissions from its coal-fired boilers for 2009 were approximately 0.319 lbs/MMBtu.

Particulate Matter

On September 21, 2006, the EPA lowered the 24-hour fine particulate ambient standard while retaining the annual standard at its current level and promulgated a new standard for inhalable coarse particulates. Based on past monitoring data, it appears that Oklahoma may be able to remain in attainment with these standards. However if parts of Oklahoma do become "non-attainment", reductions in emissions from OG&E's coal-fired boilers could be required which may result in significant capital and operating expenditures.

Ozone

Currently, the EPA has designated Oklahoma "in attainment" with the ambient standard for ozone of 0.08 parts per million ("PPM"). In March 2008, the EPA lowered the ambient primary and secondary standards to 0.075 PPM. Oklahoma had until March 2009 to designate any areas of non-attainment within the state, based on ozone levels in 2006 through 2008. Following the state's designation, the EPA was expected to determine a final designation by March 2010. States were to be required to meet the ambient standards between 2013 and 2030, with deadlines depending on the severity of their ozone level. Oklahoma City and Tulsa were the most likely areas to be designated non-attainment in Oklahoma. On September 16, 2009, the EPA announced that they would reconsider the 2008 national primary and secondary ozone standards to ensure they are scientifically sound and protective of human health. The EPA also proposed to keep the 2008 standards unchanged for the purpose of attainment and non-attainment area designations.

On January 19, 2010, the EPA published a decision to extend by one year the deadline for promulgating initial area designations for the NAAQS that were promulgated in March 2008. The new deadline is March 12, 2011.

Greenhouse Gases

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

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

Interstate Transport

On April 25, 2005, the EPA published a finding that all 50 states failed to submit the interstate pollution transport plans required by the Federal Clean Air Act as a result of the adoption of the revised ambient ozone and fine particle standards. Failure to submit these implementation plans began a two-year timeframe, starting on May 25, 2005, during which states must submit a demonstration to the EPA that they do not affect air quality in downwind states. The demonstration was properly submitted by Oklahoma to the EPA on May 7, 2007, and additional information was submitted by the state to the EPA on December 5, 2007. On June 5, 2009, a lawsuit was filed by WildEarth Guardians, a third-party, in an attempt to force the EPA to act because the EPA had not yet approved transport state implementation plans from California, Colorado, Idaho, New Mexico, North Dakota, Oklahoma and Oregon. A consent decree was proposed December 7, 2009 and the comment period closed January 5, 2010. The outcome of this matter is uncertain at this time.

EPA 2008 Information Request

In July 2008, OG&E received a request for information from the EPA regarding Federal Clean Air Act compliance at OG&E's Muskogee and Sooner generating plants. In recent years, the EPA has issued similar requests to numerous other electric utilities seeking to determine whether various maintenance, repair and replacement projects should have required permits under the Federal Clean Air Act's new source review process. OG&E believes it has acted in full compliance with the Federal Clean Air Act and new source review process and is cooperating with the EPA. On August 28, 2008, OG&E submitted information to the EPA and submitted additional information on October 31, 2008. OG&E cannot predict what, if any, further actions the EPA may take with respect to this matter.

Title V Permits and Emission Fees

At December 31, 2009, OG&E had received Title V permits for all of its generating stations and intends to continue to renew these permits as necessary. Air permit fees for OG&E's generating stations were approximately $0.9 million in 2009 and for Enogex's facilities were approximately $0.2 million in 2009.

Waste

OG&E has sought and will continue to seek, new pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2009, OG&E obtained refunds of approximately $2.4 million from its recycling efforts. This figure does not include the additional savings gained through the reduction and/or avoidance of disposal costs and the reduction in material purchases due to the reuse of existing materials. Similar savings are anticipated in future years.

Water

OG&E filed an Oklahoma Pollutant Discharge Elimination ("OPDES") permit renewal application with the state of Oklahoma on August 4, 2008 for its Seminole generating station and received a draft permit for review on January 9, 2009 and December 4, 2009. OG&E provided comments on the initial draft permit and will provide additional comments on the final draft permit during the public comment period. In addition, OG&E filed OPDES permit renewal applications for its Muskogee, Mustang and Horseshoe Lake generating stations on March 4, 2009, April 3, 2009 and October 29, 2009, respectively.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Except as otherwise stated above, in Note 14 below and in Item 3 of the Company's Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

14. Rate Matters and Regulation

Regulation and Rates

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

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

Completed Regulatory Matters

OG&E Arkansas Rate Case Filing

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

OG&E 2008 Arkansas Storm Cost Filing

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

OG&E System Hardening Filing

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

Security Enhancements

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

OG&E FERC Formula Rate Filing

On November 30, 2007, OG&E made a filing at the FERC to increase its transmission rates to wholesale customers moving electricity on OG&E's transmission lines. Interventions and protests were due by December 21, 2007. On January 31, 2008, the FERC issued an order: (i) conditionally accepting the rates, (ii) suspending the effectiveness of such rates for five months, to be effective July 1, 2008, subject to refund, (iii) establishing hearing and settlement judge procedures and (iv) directing OG&E to make a compliance filing. In July 2008, rates were implemented in an annual increase of approximately $2.4 million, subject to refund. On June 25, 2009, the FERC issued an order approving an approximate $1.3 million increase in revenues from OG&E's transmission customers compared to the approximate $2.4 million increase in revenues previously implemented in July 2008. In accordance with the FERC formula, overcollections for the prior period are to be credited to transmission customers as part of the calculation of the rates to be paid in 2010.

OG&E 2009 Oklahoma Rate Case Filing

On February 27, 2009, OG&E filed its rate case with the OCC requesting a rate increase of approximately $110 million. On July 24, 2009, the OCC issued an order authorizing: (i) an annual net increase of approximately $48.3 million in OG&E's rates to its Oklahoma retail customers, which includes an increase in the residential customer charge from $6.50/month to $13.00/month, (ii) creation of a new recovery rider to permit the recovery of up to $20 million of capital expenditures and operation and maintenance expenses associated with OG&E's smart grid project in Norman, Oklahoma, which was implemented in February 2010, (iii) continued utilization of a return on equity ("ROE") of 10.75 percent under various recovery riders previously approved by the OCC and (iv) recovery through OG&E's fuel adjustment clause of approximately $4.8 million annually of certain expenses that historically had been recovered through base rates. New electric rates were implemented August 3, 2009. OG&E expects the impact of the rate increase on its customers and service territory to be minimal over the next 12 months as the rate increase will be more than offset by lower fuel costs attributable to prior fuel over recoveries and from lower than forecasted fuel costs in 2010.

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

The OCC routinely audits activity in OG&E's fuel adjustment clause for each calendar year. In September 2008, the OCC Staff filed an application for a prudence review of OG&E's 2007 fuel adjustment clause. On August 12, 2009, all parties to this case signed a settlement agreement in this matter, stating that OG&E's generation and fuel procurement processes and costs during the 2007 calendar year were prudent. A hearing on the settlement agreement was held on September 10, 2009 and the administrative law judge recommended approval of the settlement agreement. On October 15, 2009, the OCC issued an order adopting the findings in the settlement agreement.

OG&E OU Spirit Wind Power Project

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

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

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

OG&E Renewable Energy Filing

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

OG&E to recover the costs of the power purchase agreements through OG&E's fuel adjustment clause. On January 5, 2010, OG&E received an order from the OCC approving the power purchase agreements and authorizing OG&E to recover the costs of the power purchase agreements through OG&E's fuel adjustment clause. The two wind farms are expected to be in service by the end of 2010. Negotiations with the third bidder on OG&E's short list announced in June, for an additional 150 MWs of wind energy from Texas County were terminated in early October. OG&E will continue to evaluate renewable opportunities to add to its power-generation portfolio in the future.

OG&E Windspeed Transmission Line Project

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

Market-Based Rate Authority

On December 22, 2003, OG&E and OERI filed a triennial market power update with the FERC based on the supply margin assessment test. On May 13, 2004, the FERC directed all utilities with pending three year market-based reviews to revise the generation market power portion of their three year review to address two new interim tests, a pivotal supplier screen test and a market share screen test. On February 7, 2005, OG&E and OERI submitted a compliance filing to the FERC that applied the interim tests to OG&E and OERI. On June 7, 2005, the FERC issued an order finding that OG&E and OERI had failed the market share screen test meant to determine whether entities with market-based rate authority have market power in wholesale power markets. Based on the failed market share screen test, the FERC established a rebuttable presumption that OG&E and OERI have the ability to exercise market power in OG&E's control area. On August 8, 2005, OG&E and OERI informed the FERC that they would: (i) adopt the FERC default rate mechanism for sales of one week or less to loads that sink in OG&E's control area and (ii) commit not to enter into any sales with a duration of between one week and one year to loads that sink in OG&E's control area. OG&E and OERI also informed the FERC that any new agreements for long-term sales (one year or longer in duration) to loads that sink in OG&E's control area would be filed with the FERC and that OG&E and OERI would not make such sales under their respective market-based rate tariffs. On March 21, 2006, the FERC issued an order conditionally accepting OG&E's and OERI's proposal to mitigate the presumption of market power in OG&E's control area. First, the FERC accepted the additional information related to first-tier markets submitted by OG&E and OERI, and concluded that OG&E and OERI satisfy the FERC's generation market power standard for directly interconnected first-tier control areas. Second, the FERC directed OG&E and OERI to make certain revisions to its mitigation proposal and file a cost-based rate tariff for short-term sales (one week or less) made within OG&E's control area. The FERC also expanded the scope of the proposed mitigation to all sales made within OG&E's control area (instead of only to sales sinking to load within OG&E's control area). As part of the market-based rate matter, OG&E and OERI have filed a series of tariff revisions to comply with the FERC orders and such revisions have been accepted by the FERC. Also, as part of the mitigation for the failed market share screen test discussed above, on an ongoing basis, OG&E and OERI file change of status reports and triennial market power reports according to the FERC orders and regulations. In July 2009, OG&E and OERI filed a triennial market power update with the FERC which reported that there have been no significant changes to OG&E's and OERI's market-based rate authority.

OG&E Conservation and Energy Efficiency Programs

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

Pending Regulatory Matters

SPP Transmission/Substation Projects

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

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

In 2007, the SPP notified OG&E to construct approximately 44 miles of new 345 kV transmission line which will originate at the existing OG&E Sooner 345 kV substation and proceed generally in a northerly direction to the Oklahoma/Kansas Stateline (referred to as the Sooner-Rose Hill project). At the Oklahoma/Kansas Stateline, the line will connect to the companion line being constructed in Kansas by Westar Energy. The line is estimated to be in service by June 2012. The capital expenditures related to this project are presented in the summary of capital expenditures for known and committed projects in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

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

On April 28, 2009, the SPP approved a set of 345 kV projects referred to as "Balanced Portfolio 3E". Balanced Portfolio 3E includes four projects to be built by OG&E and includes: (i) construction of approximately 120 miles of transmission line from OG&E's Seminole substation in a northeastern direction to OG&E's Muskogee substation at a cost of approximately $131 million for OG&E, which is expected to be in service by December 2014, (ii) construction of approximately 72 miles of transmission line from OG&E's Woodward District EHV substation in a southwestern direction to the Oklahoma/Texas Stateline to a companion transmission line to be built by Southwestern Public Service to its Tuco substation at a cost of approximately $120 million for OG&E, which is expected to be in service by April 2014, (iii) construction of approximately 38 miles of transmission line from OG&E's Sooner substation in an eastern direction to the Grand River Dam Authority Cleveland substation at an estimated cost of approximately $41 million for OG&E, which is expected to be in service by December 2012 and (iv) construction of a new substation near Anadarko which is expected to consist of a 345/138 kV transformer and substation breakers and will be built in OG&E's portion of the Cimarron-Lawton East Side 345 kV line at an estimated cost of approximately $8 million for OG&E, which is expected to be in service by December 2012. On June 19, 2009, OG&E received a notice to construct the Balanced Portfolio 3E projects from the SPP.

On July 23, 2009, OG&E responded to the SPP that OG&E will construct the Balanced Portfolio 3E projects discussed above beginning in early 2010. The capital expenditures related to the Balanced Portfolio 3E projects are presented in the summary of capital expenditures for known and committed projects in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Future Capital Requirements."

OG&E Smart Grid Application

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

Tallgrass Joint Venture

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

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

On July 20, 2009, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2008 fuel adjustment clause. On September 18, 2009, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. On February 2, 2010, a procedural schedule was established in this matter with a hearing scheduled for May 26, 2010.

Enogex FERC Section 311 2007 Rate Case

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

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

Enogex FERC Section 311 2009 Rate Case

On March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for its new firm East Zone Section 311 transportation service and to revise the rates for its existing East and West Zone interruptible Section 311 transportation service. In anticipation of offering this new service, Enogex had filed with the FERC, as required by the FERC's regulations, a revised Statement of Operating Conditions ("SOC") Applicable to Transportation Services to describe the terms, conditions and operating arrangements for the new service. Enogex made the SOC filing on February 27, 2009.

Enogex began offering firm East Zone Section 311 transportation service on April 1, 2009. The revised East and West Zone zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for the firm East Zone Section 311 transportation service and the increase in the rates for East and West Zone and interruptible Section 311 service are being collected, subject to refund, pending the FERC approval of the proposed rates. A number of parties intervened in both the rate case and the SOC filing and some additionally filed protests. Enogex filed answers to the interventions and protests in both matters. The FERC Staff served data requests on Enogex seeking additional information regarding various aspects of the filing and Enogex has submitted responses. On August 19, 2009, the FERC issued an order extending the time for action until it can make a determination whether Enogex's rates are fair and equitable or until the FERC determines that formal proceedings are necessary. The August 19, 2009 order also directed the FERC Staff to report to the FERC by December 29, 2009 on the status of settlement negotiations. On January 4, 2010, the FERC Staff submitted its initial settlement offer ("Offer") proposing various adjustments to Enogex's filed cost of service. Comments in response to the Offer were due on or before January 15, 2010. On January 14, 2010, Enogex asked the FERC Staff some clarifying questions regarding the Offer. Only Enogex and one intervenor filed comments on January 15, 2010, and each indicated that they were awaiting the FERC Staff's responses to the questions raised by Enogex before submitting substantive comments. The FERC Staff responded to the questions on January 20, 2010. Enogex anticipates that settlement discussions will continue.

Enogex 2010 Fuel Filing

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

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

North American Electric Reliability Corporation

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

Summary

The Energy Policy Act of 2005, the actions of the FERC and other factors are intended to increase competition in the electric industry. OG&E has taken steps in the past and intends to take appropriate steps in the future to remain a competitive supplier of electricity. While OG&E is supportive of competition, it believes that all electric suppliers must be required to compete on a fair and equitable basis and OG&E is advocating this position vigorously.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited the accompanying consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2009 and 2008, and the related consolidated statements of income, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of OGE Energy Corp. at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), OGE Energy Corp.'s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 17, 2010 expressed an unqualified opinion thereon.

As discussed in Note 1 to the consolidated financial statements, in 2009 the Company adopted Financial Accounting Standard No. 160, "Noncontrolling Interests in Consolidated Financial Statements" (ASC 810, Consolidation).

Ernst + Young LLP

Ernst & Young LLP
Oklahoma City, Oklahoma
February 17, 2010

Supplementary Data

Interim Consolidated Financial Information (Unaudited)

In the opinion of the Company, the following quarterly information includes all adjustments, consisting of normal recurring adjustments, necessary to fairly present the Company's consolidated results of operations for such periods:

(In millions, except per share data, quarter ended)	March 31	June 30	September 30	December 31	Total
Operating revenues					
2009	**$606.6**	**$ 644.1**	**$ 845.3**	**$773.7**	**$2,869.7**
2008	994.7	1,135.7	1,254.3	686.0	4,070.7
Operating income					
2009	**$ 52.0**	**$ 126.4**	**$ 229.7**	**$ 83.8**	**$ 491.9**
2008	48.1	122.7	231.2	60.1 (A)	462.1
Net income					
2009	**$ 17.6**	**$ 70.9**	**$ 137.5**	**$ 35.1**	**$ 261.1**
2008	14.6	58.8	141.4	22.6 (A)	237.4
Net income attributable to OGE Energy					
2009	**$ 16.8**	**$ 70.5**	**$ 136.8**	**$ 34.2**	**$ 258.3**
2008	13.0	57.1	139.5	21.8 (A)	231.4
Basic earnings per average common share attributable to OGE Energy common shareholders (B)					
2009	**$ 0.18**	**$ 0.73**	**$ 1.42**	**$ 0.35**	**$ 2.68**
2008	0.14	0.62	1.51	0.23 (A)	2.50
Diluted earnings per average common share attributable to OGE Energy common shareholders (B)					
2009	**$ 0.18**	**$ 0.72**	**$ 1.40**	**$ 0.35**	**$ 2.66**
2008	0.14	0.62	1.50	0.23 (A)	2.49

(A) *In the fourth quarter of 2008, OGE Energy wrote off transaction costs incurred related to the proposed joint venture between OGE Energy and Energy Transfer Partners, L.P. that was terminated and transaction costs associated with the formation of OGE Enogex Partners, L.P. of approximately $8.8 million.*

(B) *Due to the impact of dilution on the earnings per share ("EPS") calculation, the quarterly EPS amounts may not add to the total.*

Dividends

Common Stock

- Common quarterly dividends paid (as declared) in 2009 were $0.3550 each for the first three quarters of 2009 and was $0.3625 for the fourth quarter of 2009. Common quarterly dividends paid (as declared) in 2008 were $0.3475 each for the first three quarters of 2008 and was $0.3550 for the fourth quarter of 2008. Common quarterly dividends paid (as declared) in 2007 were $0.34 each for the first three quarters of 2007 and was $0.3475 for the fourth quarter of 2007.
- Present rate – $0.3625
- Payable 30th of January, April, July, and October

Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission ("SEC") rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer ("CEO") and chief financial officer ("CFO"), allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the CEO and CFO, of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the CEO and CFO have concluded that the Company's disclosure controls and procedures are effective.

No change in the Company's internal control over financial reporting has occurred during the Company's most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934).

Management's Report on Internal Control Over Financial Reporting

The management of OGE Energy Corp. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the preparation and fair presentation of published financial statements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework. Based on our assessment, we believe that, as of December 31, 2009, the Company's internal control over financial reporting is effective based on those criteria.

The Company's independent auditors have issued an attestation report on the Company's internal control over financial reporting. This report appears on the following page.

Peter B. Delaney
Chairman of the Board,
President and
Chief Executive Officer

Danny P. Harris
Senior Vice President
and Chief Operating Officer

Sean Trauschke
Vice President and
Chief Financial Officer

Scott Forbes
Controller and
Chief Accounting Officer

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited OGE Energy Corp.'s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). OGE Energy Corp.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, OGE Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2009 and 2008, and the related consolidated statements of income, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2009 of OGE Energy Corp. and our report dated February 17, 2010 expressed an unqualified opinion thereon.

Ernst + Young LLP

Ernst & Young LLP
Oklahoma City, Oklahoma
February 17, 2010

Historical Performance

(In millions except per share data)	2009 [A]	2008	2007	2006	2005
Selected Financial Data					
Operating revenues	**$2,869.7**	$ 4,070.7	$ 3,797.6	$ 4,005.6	$ 5,911.5
Cost of goods sold	**1,557.7**	2,818.0	2,634.7	2,902.5	4,942.3
Gross margin on revenues	**1,312.0**	1,252.7	1,162.9	1,103.1	969.2
Other operating expenses	**820.1**	790.6	707.6	670.4	646.8
Operating income	**491.9**	462.1	455.3	432.7	322.4
Interest income	**1.4**	6.7	2.1	6.2	3.5
Allowance for equity funds used during construction	**15.1**	–	–	4.1	–
Other income (loss)	**27.5**	15.4	17.4	16.3	(0.3)
Other expense	**16.3**	25.6	22.7	16.7	5.5
Interest expense	**137.4**	120.0	90.2	96.0	90.3
Income tax expense	**121.1**	101.2	116.7	120.5	68.6
Income from continuing operations	**261.1**	237.4	245.2	226.1	161.2
Income from discontinued operations, net of tax	**–**	–	–	36.0	49.8
Net income	**261.1**	237.4	245.2	262.1	211.0
Less: net income attributable to noncontrolling interest	**2.8**	6.0	1.0	–	–
Net income attributable to OGE Energy	**$ 258.3**	$ 231.4	$ 244.2	$ 262.1	$ 211.0
Diluted earnings per average common share					
Income from continuing operations	**$ 2.66**	$ 2.49	$ 2.64	$ 2.45	$ 1.77
Income from discontinued operations, net of tax	**–**	$ –	$ –	$ 0.39	$ 0.55
Income per average common share	**$ 2.66**	$ 2.49	$ 2.64	$ 2.84	$ 2.32
Long-term debt	**$2,088.9**	$ 2,161.8	$ 1,344.6	$ 1,346.3	$ 1,350.8
Total assets	**$7,266.7**	$ 6,518.5	$ 5,237.8	$ 4,898.4	$ 4,871.4
Common Stock Statistics					
Dividends paid per share	**$ 1.42**	$ 1.39	$ 1.36	$ 1.33	$ 1.33
Dividends declared per share	**$ 1.4275**	$ 1.3975	$ 1.3675	$ 1.3375	$ 1.33
Book value	**$ 21.06**	$ 20.28	$ 18.31	$ 17.56	$ 15.19
Market price – year end	**$ 36.89**	$ 25.78	$ 36.29	$ 40.00	$ 26.79
Price/earnings ratio – year end	**13.9**	10.3	13.6	13.9	11.4
Basic average shares outstanding (millions)	**96.2**	92.4	91.7	91.0	90.3
Diluted average shares outstanding (millions)	**97.2**	92.8	92.5	92.1	90.8
Actual shares outstanding (millions)	**97.0**	93.5	91.8	91.2	90.6
Number of shareowners	**21,971**	22,705	23,983	25,198	26,369
Capitalization Ratios [B]					
Common equity	**46.4%**	47.0%	55.7%	54.3%	50.5%
Long-term debt	**53.6%**	53.0%	44.3%	45.7%	49.5%
Miscellaneous Statistics					
Electric customers	**776,550**	770,088	762,234	754,840	745,493
Mwh sales (millions)	**26.9**	28.2	27.1	26.4	26.1
Mw generating capability – year end (thousands)	**6.6**	6.8	6.2	6.1	6.1
Mw peak demand (thousands)	**6.4**	6.5	6.3	6.5	6.1
Fuel mix (generation only, by kwh generated)					
Natural gas	**38%**	30%	36%	33%	30%
Coal	**60%**	68%	62%	67%	70%
Wind	**2%**	2%	2%	–%	–%
Cost (per million Btu)					
Natural gas	**$ 4.02**	$ 8.40	$ 6.77	$ 7.10	$ 8.76
Coal	**$ 1.65**	$ 1.11	$ 1.10	$ 1.10	$ 0.98
Weighted average	**$ 2.50**	$ 3.30	$ 3.13	$ 2.98	$ 3.21
Total gas throughput volumes (trillion Btu/day)	**1.79**	1.57	1.52	1.44	1.31
Total natural gas processed (trillion Btu/day)	**0.70**	0.66	0.57	0.54	0.52
Total natural gas liquids sold (million gallons)	**493**	426	385	371	302
Average sales price per gallon	**$ 0.770**	$ 1.255	$ 1.048	$ 0.902	$ 0.873
Estimated keep-whole spreads [C]	**$ 4.12**	$ 6.15	$ 5.35	$ 3.99	$ 2.51

[A] Effective January 1, 2009, the Company changed the presentation of Enogex's noncontrolling interest in the Atoka Midstream, LLC joint venture in the Company's consolidated financial statements related to the adoption of a new accounting principle and restated prior periods for consistency.

[B] Capitalization ratios = [Stockholders' equity/(Stockholders' equity + Long-term debt + Long-term debt due within one year)] and [(Long-term debt + Long-term debt due within one year)/(Stockholders' equity + Long-term debt + Long-term debt due within one year)].

[C] The estimated realized keep-whole spread is an approximation of the spread between the weighted-average sales price of the retained natural gas liquids ("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 Federal Energy Regulatory Commission monthly index posting for Panhandle Eastern Pipe Line Co., Texas, Oklahoma, for the forward month contract for natural gas prices.

Investor Information

Annual Meeting
The annual meeting of shareowners is scheduled for 10 a.m. Thursday, May 20, 2010, at the National Cowboy & Western Heritage Museum, 1700 NE 63rd St., Oklahoma City. The Board of Directors will request proxies for this meeting and statements will be mailed to shareowners on or about March 31, 2010.

Ticker Symbol Information
The New York Stock Exchange lists OGE Energy Corp. common stock for trading under the symbol OGE. Quotes appear in daily newspapers where the common stock is listed as "OGE Engy" in the New York Stock Exchange table.

Stock Exchange Listing
New York Stock Exchange
OGE Energy Corp.
Common stock

Form 10-K
A copy of the Annual Report to the Securities and Exchange Commission, Form 10-K, will be furnished without charge to any shareowner upon written request by contacting:

Todd Tidwell
OGE Energy Corp.
Investor Relations, MC 804
P.O. Box 321
Oklahoma City, OK 73101-0321

Shareowner Information
Shareowners with questions or in need of assistance concerning their OGE stock accounts should contact OGE's registrar, stock plan administrator, transfer agent and dividend disbursing agent:

BNY Mellon Shareowner Services
P.O. Box 358035
Pittsburgh, PA 15252-8035
Phone toll free: 1-888-216-8114
Internet account access:
www.bnymellon.com/shareowner/isd
or www.oge.com

Additional Information
Shareowners, analysts, brokers and institutional investors with questions or comments may contact Todd Tidwell, Director, Investor Relations at (405) 553-3966.

Stock Purchase Plan
This plan offers a convenient and economical way to purchase OGE Energy Corp. common stock. To enroll, investors are required to make a minimum initial investment of $250. Once enrolled, participants may make optional investments from at least $25 per investment up to a maximum of $100,000 per year. Additional investments may be made electronically via Internet account access. Participants may choose to have all or any portion of their dividends reinvested. Additional features of the plan include: certificate safekeeping, automatic monthly investments and direct deposit of dividends. Online enrollment and plan materials are available on the Internet at www.oge.com or a prospectus and enrollment packet may be obtained by calling 1-866-353-7849. Please read the prospectus thoroughly before enrolling in the plan.

Market Price of Common Stock
The following table gives information with respect to price ranges, as reported in *The Wall Street Journal* as New York Stock Exchange Composite Transactions, for the periods shown.

	High	Low
2010		
First Quarter (through February 28)	$37.92	$34.92
2009		
First Quarter	$26.80	$19.70
Second Quarter	28.55	23.19
Third Quarter	33.72	26.50
Fourth Quarter	37.79	31.66
2008		
First Quarter	$36.23	$29.83
Second Quarter	34.02	30.61
Third Quarter	34.74	29.67
Fourth Quarter	31.41	19.56

The number of record holders of the Company's Common Stock at February 28, 2010, was 21,892. The reported closing market price of the Company's Common Stock on the New York Stock Exchange on February 28, 2010, was $36.56.

Dividend Direct Deposit
Shareowners may have their dividends deposited directly into their checking, savings or money market accounts. To take advantage of this service, please contact the registrar.

Duplicate Annual Reports
Annual reports are typically mailed for each separate shareowner registration. To eliminate duplicate mailings please contact the registrar.

Corporate Governance
All of OGE Energy Corp.'s corporate governance material, including codes of conduct, guidelines for corporate governance and committee charters, is available for public viewing on the OGE Energy web site at www.oge.com under the heading "Investor Relations," "Corporate Governance." OGE Energy Corp.'s corporate governance material also is available upon request sent to OGE Energy Corp.'s Corporate Secretary.

Positive Energy is a registered trademark of OGE Energy Corp.
OGE Energy Corp. is an equal opportunity employer.

OGE Energy Corp. employees are consistently generous contributors to the United Way. In 2009, our company's employees pledged more than $828,000 to United Way campaigns in communities where they live and work.

Design: Coates and Coates. Printing: Southwestern.

OG+E P.O. Box 321 Oklahoma City, Oklahoma 73101-0321 (405) 553-3000