

positive  
energy®

## Financial Highlights

### OGE Energy Corp.

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.

### Oklahoma Gas and Electric Company

Oklahoma Gas and Electric Company serves more than 770,000 retail customers in Oklahoma and western Arkansas, and a number of wholesale customers throughout the region. OG&E, with about 6,800 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

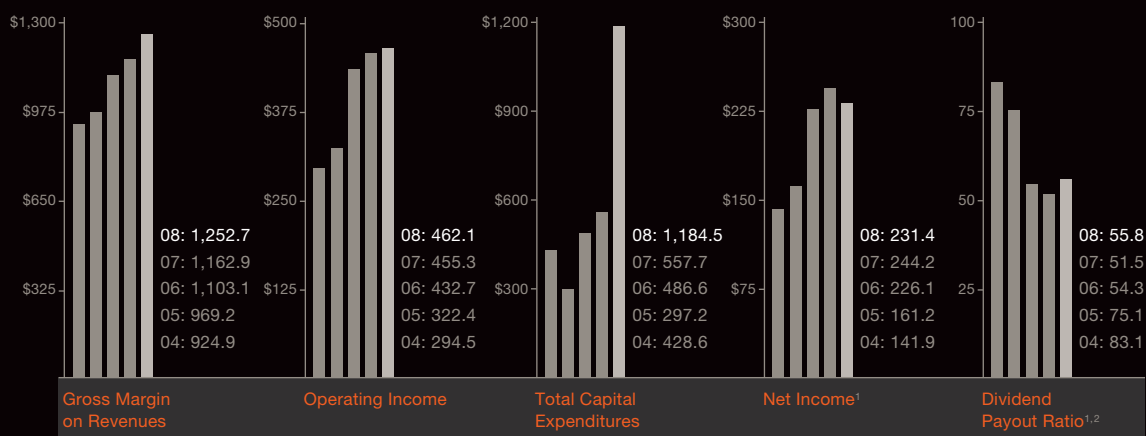
Enogex operates a pipeline system engaged in natural gas gathering, processing, transportation and storage. The system includes about 8,200 miles of pipe, seven natural gas processing plants and 24 billion cubic feet of natural gas storage capacity.

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## 2008 Highlights

Dollars in millions unless noted



<sup>1</sup> From continuing operations

<sup>2</sup> Percent

## Letter to Shareowners

Navigating the near-term circumstances of economic recession, OG&E and Enogex are well positioned. Our long-term view is positive, and we're moving ahead with thoughtful plans for investment and growth.

*Positive Energy* is a phrase we use to convey our commitment to doing the right things and doing them well. Today, it means we're tightening our belt for current business conditions while also executing our long-term plans to expand and improve our assets and operations.

We earned \$2.49 per share in 2008 and increased our dividend for the third year in a row, a solid performance that enables us to focus on future growth. Enogex set a new record for net income as commodity prices reached all-time highs before falling late in the year. OG&E also performed well in line with expectations, considering its electric rates are based on 2004 costs.

**It's the economy** that has everyone's attention and, fortunately, our region has fared better to date than the nation as a whole. At OG&E, we project modest growth in electric demand and sales in 2009. As the utility continues to implement its strategy, new electric transmission lines are being built. More wind farms are coming, and we're proposing our next big step with "smart grid" technology. At the same time, to ensure that OG&E's prices cover the cost of doing business, we're pursuing general rate cases in Oklahoma and Arkansas. Appropriate regulatory relief will enable us to continue a long record of reliable service at well below average rates.

Enogex also is appropriately positioned to weather the economic and market conditions that have reduced commodity-based margins and curbed volume growth. While lower natural gas prices are curtailing drilling and production, we do see enough activity in our key areas to forecast higher volumes of gas gathered into the Enogex system. We also expect our disciplined approach to investment and operations to sustain a solid financial performance.

**Looking ahead**, we want to avoid the need for additional fossil fuel-based electric generation until 2020. It's an ambitious goal. To reach it, we will need new approaches that embrace renewables while also supporting innovative technologies for partnering with our customers. Customers, after all, determine how much power we must supply. Working together, we want to help them conserve energy and use it more wisely.

In these times of fast-paced change and uncertainty, *Positive Energy* also means continued adherence to our time-honored values including integrity, teamwork and public service. Our shareowners deserve and expect no less, and for your continued support, we thank you.



A handwritten signature in black ink that reads "Peter B. Delaney". The signature is fluid and cursive, with a large initial "P".

**Peter B. Delaney**  
Chairman, President and  
Chief Executive Officer

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Our strength and experience are in electricity and natural gas, energy sources that sustain our economy today and will fuel its future growth.

As a “back to basics” mindset takes hold in homes and businesses across the country, our customers, investors, employees and communities should take comfort in the knowledge that such thinking represents no change for us.

OGE Energy Corp. is a company always focused on our core strengths, executing thoughtful strategies to better serve customers, improve business performance and grow our utility and pipeline businesses.

In good times and bad, this is what we do. We watch our costs, striving to do things right. We survey the landscape ahead, formulate our strategy and execute. We focus on the details, starting and ending with working safely. We value not only efficiency, but also effectiveness, encouraging a culture of continuous improvement. For example, OGE’s response to the disastrous ice storm of December 2007 won the highest national distinction, yet we proceeded with a full-scale review of our plans and procedures and found a number of ways to perform even better.

We take care to plan ahead, invest wisely and operate prudently. This fundamental approach has led to positive regulatory outcomes, productive business relationships, high customer satisfaction and shareowner value.



Even as OG&E and Enogex reduce day-to-day operating costs, they continue to invest in core operations. Capital project budgets for 2009 include \$600 million for OG&E and \$200 million for Enogex.



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OG&E is ideally positioned to generate and transmit electricity from the abundant wind resources of northwestern Oklahoma.

America wants more energy from renewable sources, and OG&E is ideally positioned to provide it. To our existing 170 megawatts of wind power, OG&E next will add the OU Spirit wind farm; 100 megawatts dedicated to helping the University of Oklahoma reach its goal to run on 100 percent renewable energy by 2013. OG&E also plans to add up to 600 additional megawatts of wind power in separate projects by 2012.

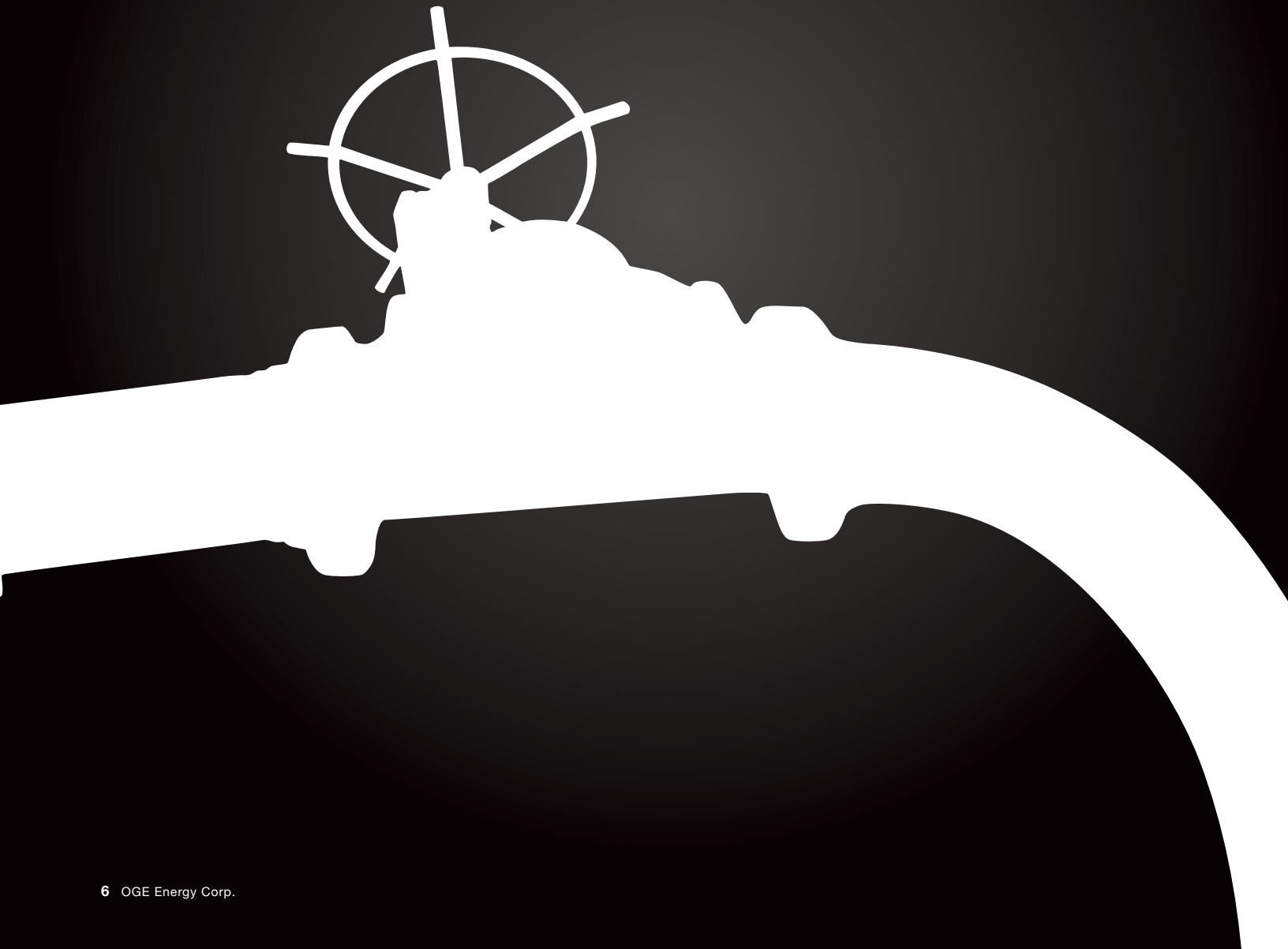
The best sites for wind farms require new transmission lines, such as the one OG&E is building from Woodward to Oklahoma City. Even more transmission is on the OG&E drawing board, including components of a regional wind power superhighway planned with partners American Electric Power and MidAmerican Energy Holdings Co.

To avoid additional fossil-fuel based electric generation for at least a decade, OG&E also seeks to expand its *Smart Power* program, giving customers the opportunity to reduce consumption and control their energy costs.



*Smart Power* technology from OG&E allows customers to monitor their electric meter from inside their home and view costs in real time, enabling them to more effectively manage their use of energy.

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With a balanced portfolio of successful utility and pipeline operations, we're applying thoughtful strategies for continued growth.

Our electric utility and natural gas pipeline are asset-based businesses, continuously striving to improve their operations and expand their systems.

OG&E in the past four years has spent \$1.6 billion on its electric system, with major projects including construction of the Centennial wind farm in 2007 and acquisition of the Redbud power plant in 2008. These investments, and others that benefit customers with enhanced system reliability, are recovered through the utility regulatory process. OG&E has a strong case to make in 2009.

Enogex also has grown through strategic investments in system infrastructure, with projects totaling \$500 million during the last two years alone. The Gulf Crossing and Mid-American Express projects, announced in 2006, both are set to begin leasing significant pipeline capacity from Enogex in 2009. Economic and market conditions have led to cost-cutting and slowed the rate of growth for some in the natural gas industry, but for Enogex, a number of planned expansion projects and pursuit of new strategic opportunities will continue.



OG&E will expand its electric transmission network and unlock northwestern Oklahoma's wind power potential with construction of the 120-mile Woodward-to-Oklahoma City line, an investment of more than \$200 million.

## Leadership



Board of Directors, left to right: Luke Corbett, Wayne Brunetti, Leroy Richie, Linda Lambert, Pete Delaney, J.D. Williams, John Groendyke and Robert Kelley. Not pictured are Robert Lorenz and Kirk Humphreys.

### 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<sup>3</sup>

Former Chairman and  
Chief Executive Officer,  
Kerr-McGee Corporation  
Oklahoma City

#### Robert Kelley<sup>1,3</sup>

President,  
Kellco Investments Inc.  
Ardmore, Oklahoma

#### J.D. Williams<sup>2,3</sup>

Retired Partner,  
Williams & Jensen, P.C.  
Washington, D.C.

#### Wayne Brunetti<sup>3</sup>

Retired Chairman,  
Xcel Energy Inc.  
Denver, Colorado

#### John D. Groendyke<sup>2,3</sup>

Chairman and  
Chief Executive Officer,  
Groendyke Transport, Inc.  
Enid, Oklahoma

#### Kirk Humphreys<sup>1,3</sup>

Chairman,  
Oklahoma District Council  
of the Urban Land Institute  
Oklahoma City

#### Linda P. Lambert<sup>1,2</sup>

President,  
LASSO Corporation  
Oklahoma City

#### Robert O. Lorenz<sup>1,2</sup>

Retired Managing Partner,  
Arthur Andersen  
Oklahoma City

#### Leroy C. Richie<sup>2,3</sup>

Counsel,  
Lewis & Munday, P.C.  
Detroit, Michigan

### 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

#### Scott Forbes

Controller,  
Chief Accounting Officer and  
Interim Chief Financial Officer

#### Carla D. Brockman

Vice President, Administration/  
Corporate Secretary

#### Robert E. Grasty

Vice President, Human Resources

#### Gary D. Huneryager

Vice President, Internal Audits

#### S. Craig Johnston

Vice President, Strategic  
Planning and Marketing

#### Cristina F. McQuiston

Vice President, Process and  
Performance Improvement

#### Max J. Myers

Treasurer and Managing  
Director, Corporate  
Development and Finance

#### Reid V. Nuttall

Vice President, Enterprise  
Information and Performance

#### Jerry A. Peace

Chief Risk Officer

#### Paul L. Renfrow

Vice President, Public Affairs

#### John D. Rhea

Assistant Corporate Secretary  
and Corporate Compliance Officer

### 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

#### John Wendling, Jr.

Vice President, Power Supply

### Enogex LLC

#### E. Keith Mitchell

Senior Vice President and  
Chief Operating Officer

#### Paul M. Brewer

Vice President, Operations

#### Patricia D. Horn

Vice President,  
General Counsel

#### Thomas L. Levescy

Controller and  
Chief Accounting Officer

#### Stephen E. Merrill

Chief Financial Officer

#### Ramiro F. Rangel

Vice President,  
Commercial Operations

#### Dwaine A. Shroyer

Vice President,  
Business Development

### OGE Energy Resources, Inc.

#### Craig R. Jimenez

President

<sup>1</sup> Member of the audit committee

<sup>2</sup> Member of the nominating and  
corporate governance committee

<sup>3</sup> Member of the compensation committee

Red number indicates committee chairman

2008

Financial Section

OGE Energy Corp. Annual Report

# Financial Performance

## OGE Energy Corp. Common Stock Data

	2008	2007	2006 <sup>(A)</sup>	2005 <sup>(B)</sup>	2004 <sup>(B)</sup>
Diluted earnings per share	\$ 2.49	\$ 2.64	\$ 2.84	\$ 2.32	\$ 1.73
Diluted earnings per share from continuing operations	\$ 2.49	\$ 2.64	\$ 2.45	\$ 1.77	\$ 1.60
Dividends paid per share	\$ 1.39	\$ 1.36	\$ 1.33	\$ 1.33	\$ 1.33
Price range	\$36.23 – 19.56	\$41.30 – 29.12	\$40.58 – 26.34	\$30.60 – 24.41	\$26.95 – 22.85
Price/earnings ratio – year end	10.3	13.6	13.9	11.4	15.2
Return on equity – average	13.1%	14.9%	17.9%	16.0%	12.4%
Diluted average common shares outstanding (millions)	92.8	92.5	92.1	90.8	88.5

## Oklahoma Gas and Electric Company

(In millions except EPS, before elimination of inter-segment items)

	2008	2007	2006	2005	2004
Operating revenues	\$1,960	\$1,835	\$1,746	\$1,721	\$1,578
Gross margin on revenues	\$ 845	\$ 810	\$ 796	\$ 727	\$ 664
Operating income	\$ 278	\$ 292	\$ 294	\$ 232	\$ 192
Net income	\$ 143	\$ 162	\$ 149	\$ 130	\$ 108
Diluted earnings per share	\$ 1.54	\$ 1.75	\$ 1.62	\$ 1.43	\$ 1.22
Return on equity – average	9.3%	12.0%	12.8%	12.0%	11.0%
Total electricity sales (millions of megawatt hours)	28.2	27.1	26.4	26.1	24.8

## Enogex

(In millions except EPS, before elimination of inter-segment items)

	2008	2007	2006	2005 <sup>(B)</sup>	2004 <sup>(B)</sup>
Operating revenues	\$1,103	\$2,065	\$2,368	\$4,332	\$3,380
Gross margin on revenues	\$ 393	\$ 353	\$ 307	\$ 242	\$ 262
Operating income	\$ 185	\$ 164	\$ 139	\$ 90	\$ 103
Net income	\$ 91	\$ 86	\$ 114	\$ 90	\$ 61
Diluted earnings per share	\$ 0.98	\$ 0.93	\$ 1.23	\$ 0.99	\$ 0.69
Return on equity – average	24.9%	21.9%	26.2%	18.5%	12.9%
Pipeline throughput (Tbtu/y) <sup>(C)</sup>	575	555	526	478	449

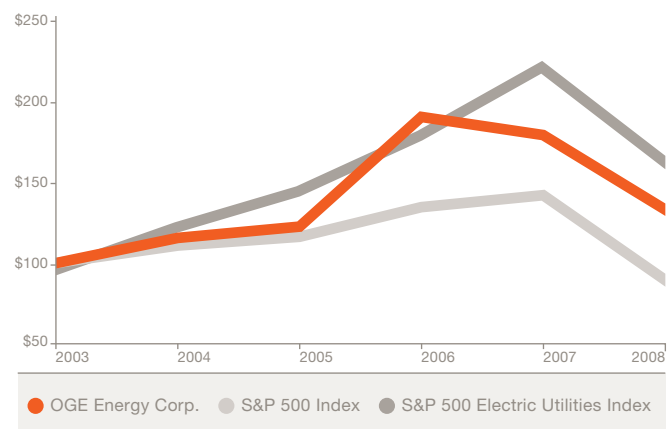
<sup>(A)</sup> The Company adopted SFAS No. 123 (Revised), "Share-Based Payment," using the modified prospective transition method, effective January 1, 2006, which required the Company to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award.

<sup>(B)</sup> Amounts for 2005 and 2004 were restated for discontinued operations related to the sale of Enogex assets in May 2006.

<sup>(C)</sup> 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, 2003, and that all dividends were reinvested. As of Dec. 31, 2008, the closing price of the Company's common stock on the New York Stock Exchange was \$25.78.



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

### Introduction

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

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

Enogex LLC and its subsidiaries ("Enogex") is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located primarily in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's ongoing operations are organized into two business segments: (1) natural gas transportation and storage and (2) natural gas gathering and processing. Historically, Enogex had also engaged in natural gas marketing through its former subsidiary, OGE Energy Resources, Inc. ("OERI"). 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. Accordingly, the discussion that follows includes the results of OERI, but as of January 1, 2008, Enogex no longer has any interest in the results of OERI. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream, LLC joint venture through Enogex Atoka LLC ("Atoka"), a wholly owned subsidiary of Enogex.

Effective April 1, 2008, Enogex Inc. converted from an Oklahoma corporation to a Delaware limited liability company. Also, effective April 1, 2008, Enogex Products Corporation ("Products"), a wholly owned subsidiary of Enogex, converted from an Oklahoma corporation to an Oklahoma limited liability company.

In September 2008, OGE Energy and Energy Transfer Partners, L.P. ("ETP") entered into an agreement to form a joint venture combining Enogex's midstream business with ETP's interstate operations as well as its midstream operations in the Rocky Mountains. One of the conditions to completing the joint venture was obtaining financing that met the minimum specified terms the parties had agreed to in the joint venture agreement. Under the terms of the agreement, if OGE Energy and ETP did not complete the financing and close the joint venture by March 31, 2009, either OGE Energy or ETP could terminate the contribution agreement relating to the formation of the joint venture. Due to the

significant downturn in the national economy and resulting uncertainty in the capital markets, the parties determined that obtaining the financing and completing the formation of the joint venture was not feasible and not in their best interests. Accordingly, on February 12, 2009, the parties terminated the agreement to form the joint venture.

In light of the September 28, 2008 announcement of the proposed joint venture as well as market conditions, OGE Enogex Partners, L.P., a partnership formed by the Company to further develop Enogex's natural gas midstream assets and operations, which had previously filed a registration statement with the SEC for a proposed initial public offering of its common units, has determined not to proceed with the offering contemplated by the registration statement and withdrew the registration statement on September 23, 2008.

In July 2008, OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture to construct high-capacity transmission line projects in western Oklahoma. The Company will own 50 percent of the joint venture. The joint venture is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. Work on the joint venture projects is scheduled to begin in late 2009 and is targeted for completion by the end of 2013. The joint venture's initial projects will include 765 kilovolt lines from Woodward 120 miles northwest to Guymon in the Oklahoma Panhandle and from Woodward 50 miles north to the Kansas border. A Southwest Power Pool ("SPP") study estimates cost for the two projects to be approximately \$500 million, of which OGE Energy's portion will be approximately \$250 million. For additional information regarding this joint venture, see Note 15 of Notes to Consolidated Financial Statements.

### 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 long-term financial goals include earnings growth of four to five percent on a weather-normalized basis, an annual total return in the top third of its peer group, dividend growth, maintenance of a dividend payout ratio consistent with its peer group and maintenance of strong credit ratings. The Company believes it can accomplish these financial goals 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 at the utility to improve 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 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:

- OG&E purchased a 77 percent interest in the 520 megawatt (“MW”) natural gas-fired, combined-cycle NRG McClain Station in July 2004;
- OG&E entered into an agreement in February 2006 to engineer, procure and construct a wind generation energy system for a 120 MW wind farm (“Centennial”) in northwestern Oklahoma. The wind farm was fully in service in January 2007;
- 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 in July 2008 to construct high-capacity transmission line projects in western Oklahoma which is intended to allow the companies to lead development of renewable wind with the planned transmission construction from Woodward northwest to Guymon in the Oklahoma Panhandle and from Woodward north to the Kansas border;
- 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 a future wind project (“OU Spirit”) in western Oklahoma which is expected to be in service by the end of 2009;
- OG&E purchased a 51 percent interest in the 1,230 MW natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma (the “Redbud Facility”) in September 2008;
- OG&E issued a request for proposal (“RFP”) for wind power in December 2008 for up to 300 MWs of new capability which OG&E intends to add to its power-generation portfolio no later than the end of 2010; and
- OG&E’s construction initiative from 2009 to 2014 includes approximately \$2.7 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. In 2008, OG&E established a “Quick Start” Demand Side Management program to encourage more efficient use of electricity. OG&E also announced a “Positive Energy SmartPower” initiative (commonly referred to in the industry as “Smart Grid” technologies) that will empower customers to proactively manage their energy consumption during periods of peak demand. 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.

The increase in wind power generation and the building of the transmission lines are subject to numerous regulatory and other approvals, including appropriate regulatory treatment from the OCC and, in the case of the 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 Note 16 of Notes to Consolidated Financial Statements.

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 (“NGL”) prices. Because of the natural decline in production from existing wells connected to Enogex’s systems, Enogex’s success depends on its ability to gather new sources of natural gas, which depends on certain factors beyond its or our control. Any decrease in supplies of natural gas could adversely affect Enogex’s gathering and processing business. As a result, Enogex’s cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on its gathering systems and the asset utilization rates at its natural gas processing plants, Enogex must continually obtain new natural gas supplies. The primary factors affecting Enogex’s ability to obtain new supplies of natural gas and attract new customers to its assets depends in part on the level of successful drilling activity near these systems, Enogex’s ability to compete for volumes from successful new wells and Enogex’s ability to expand capacity as needed.

Enogex 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 and increased utilization of existing assets and strategic acquisitions. 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. Over the past several years, Enogex has initiated multiple organic growth projects. Currently, Enogex’s organic growth capital expenditures are focused on three primary areas:

- Upgrades to Enogex's existing transportation system due to increased volumes as a result of the broader shift of gas flow from the Rocky Mountains and the mid-continent to markets in the northeast and southeast United States;
- 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 the Atoka joint venture; and
- Expansions on the west side of Enogex's gathering system, primarily in the Granite Wash play and Atoka play in the Wheeler County, Texas area, which is located in the Texas Panhandle.

For additional information regarding current or recently completed projects, see Note 15 of Notes to Consolidated Financial Statements.

In addition to focusing on growing its earnings, Enogex has reduced its exposure to changes in commodity prices and minimized its exposure to keep-whole processing arrangements. Enogex's profitability increased significantly from 2003 to 2008 due to the performance improvement plan initiated in 2002 as well as an overall favorable business environment coupled with higher commodity prices. While the Company believes substantial progress has been achieved, additional opportunities remain. Enogex continues to review its work processes, evaluate the rationalization of assets, negotiate better terms for both new contracts and replacement contracts, manage costs and pursue opportunities for organic growth, all in an effort to further improve its cash flow and net income, while at the same time decreasing the volatility associated with commodity prices.

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 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

Prior to January 1, 2008, Enogex had engaged in natural gas marketing through OERI. On January 1, 2008, Enogex distributed the stock of OERI to OGE Energy. Accordingly, in the discussions below regarding the results of Enogex, the results of OERI are only included for the years ended December 31, 2007 and 2006.

#### 2008 Compared to 2007

The Company reported net income of 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 of approximately \$12.8 million, or \$0.15 per diluted share, during 2008 as compared to 2007 was primarily due to:

- A decrease in net income at OG&E 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 on revenues ("gross margin") due to increased rates from various regulatory riders implemented during 2008 and lower income tax expense;
- An increase in net income at Enogex 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
- An increase in the net loss at OGE Energy of approximately \$3.4 million, or \$0.03 per diluted share of the Company's common stock, in 2008 compared to 2007 primarily due to higher operation and maintenance expense related to the write-off of transaction costs incurred related to the proposed joint venture between OGE Energy and ETP that has subsequently been 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 and a higher income benefit due to a higher net loss.

#### 2007 Compared to 2006

The Company reported net income of approximately \$244.2 million, or \$2.64 per diluted share, in 2007 as compared to approximately \$262.1 million, or \$2.84 per diluted share, in 2006. The decrease in net income of approximately \$17.9 million, or \$0.20 per diluted share, during 2007 as compared to 2006 was primarily due to:

- An increase in net income at OG&E of approximately \$12.4 million, or \$0.13 per diluted share of the Company's common stock, in 2007 as compared to 2006 primarily due to a higher gross margin from higher rates from the Centennial wind farm rider, security rider and Arkansas rate case, increased peak demand and related revenues by non-residential customers in OG&E's service territory and new customer growth in OG&E's service territory partially offset by cooler weather in OG&E's service territory. Also contributing to the increase in net income was lower interest expense and lower income tax expense partially offset by higher depreciation and amortization expense;

- A decrease in net income at Enogex (including discontinued operations) of approximately \$27.3 million, or \$0.30 per diluted share of the Company's common stock, in 2007 as compared to 2006, of which \$0.39 per diluted share was due to a reduction in earnings associated with discontinued operations. This decrease was partially offset by an increase of approximately \$0.09 per diluted share associated with continuing operations primarily due to higher gross margins in each of Enogex's segments partially offset by higher operation and maintenance expenses, lower other income and higher income tax expense; and
- A net loss at OGE Energy of approximately \$3.7 million, or \$0.04 per diluted share of the Company's common stock, in 2007, as compared to a net loss of approximately \$0.7 million, or \$0.01 per diluted share, in 2006 primarily due to an income tax adjustment recorded in 2006.

#### 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, Credit and Commodity Markets

As a result of recent volatile conditions in global capital markets, including the bankruptcy filing of Lehman Brothers Holdings, Inc. ("Lehman"), general liquidity in short-term credit markets has been constrained despite several pro-active intervention measures undertaken by the Federal Reserve, the Department of the Treasury, the United States Congress and the President of the United States. As explained in more detail below, OGE Energy and OG&E historically have maintained access to short-term liquidity through the A2/P2 commercial paper market and utilization of direct borrowings on certain committed credit agreements, although the ability to access the commercial paper market has been more limited in recent months.

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

On September 15, 2008, Lehman filed for bankruptcy protection and has not funded their portion of OGE Energy's and OG&E's revolving credit agreements. At December 31, 2008, approximately \$4 million and \$11 million, respectively, of OGE Energy's and OG&E's revolving credit agreements are not available as this portion was assigned to Lehman. The Company has no direct credit exposure in its short-term wholesale and commodity trading activity to Lehman or its subsidiaries.

Enogex's gathering and processing margins generally improve when NGL prices are high relative to the price of natural gas (sometimes referred to as high commodity spreads). For much of the first nine months of 2008, commodity spreads were relatively high. Recently, commodity spreads have been significantly lower. If this trend continues, Enogex's results for 2009 will be affected as its 2008 results were affected. See 2009 Outlook below. Also, prices of natural gas and NGLs have been extremely volatile, and Enogex expects this volatility to continue.

##### Acquisition of Redbud Power Plant

On September 29, 2008, OG&E acquired a 51 percent interest in the Redbud Facility for approximately \$434.5 million. OG&E will jointly own the Redbud Facility with the Oklahoma Municipal Power Authority ("OMPA") and the Grand River Dam Authority ("GRDA"), and OG&E will act as the operations manager and perform the day-to-day operation and maintenance of the Redbud Facility. Each of the joint owners will be entitled to its respective portion of the output and will pay its pro rata share of all costs of operating and maintaining the Redbud Facility. OG&E implemented a rider at the end of September 2008 to recover the Oklahoma jurisdiction revenue requirement until new rates are implemented that include Redbud's net investment, operation and maintenance expense, depreciation expense and ad valorem taxes. For additional information regarding the acquisition of the Redbud Facility, see Note 16 of Notes to Consolidated Financial Statements.

##### Cancelled Red Rock Power Plant and Storm Cost Recovery Rider

On October 11, 2007, the OCC issued an order denying OG&E and Public Service Company of Oklahoma's ("PSO") request for pre-approval of their proposed 950 MW Red Rock coal-fired power plant project. As a result, on October 11, 2007, OG&E, PSO and the OMPA agreed to terminate agreements to build and operate the plant. At December 31, 2007, OG&E had incurred approximately \$17.5 million of capitalized costs associated with the Red Rock power plant project. In December 2007, OG&E filed an application with the OCC requesting authorization to defer, and establish a method of recovery of, approximately \$14.7 million of Oklahoma jurisdictional costs associated with the Red Rock power plant project. On June 27, 2008, OG&E filed an application requesting a Storm Cost Recovery Rider ("SCRR") for the years 2007 through 2009 to recover excess storm damage costs (\$35.9 million at December 31, 2007) and, at the same time, filed a motion to consolidate for hearing the Red Rock application and the SCRR application. On July 24, 2008, a settlement agreement was signed by all the parties involved in the two cases. Under the terms of the settlement agreement, OG&E will: (i) recover approximately \$7.2 million, or 50 percent, of the Oklahoma jurisdictional portion of the Red Rock power plant deferred costs through a regulatory asset, (ii) amortize the Red Rock



regulatory asset over a 27-year amortization period and earn the OCC's authorized rate of return beginning with OG&E's next rate case, (iii) accrue carrying costs on the debt portion of the Red Rock regulatory asset from October 1, 2007 until the date OG&E begins to recover the regulatory asset through the base rates established in OG&E's next rate case, (iv) recover the OCC Staff and Attorney General consulting fees of approximately \$0.3 million related to the Red Rock pre-approval case, in OG&E's next rate case by amortizing this over a two-year period, (v) recover approximately \$33.7 million of the 2007 storm costs regulatory asset, which resulted in a write-down of approximately \$1.5 million, (vi) implement the SCRR to recover OG&E's actual storm expense for the four-year period from 2006 through 2009, (vii) retain the first \$3.4 million from the sale of excess sulfur dioxide ("SO<sub>2</sub>") allowances, (viii) reduce storm costs recovered through the SCRR by the proceeds from the sale of SO<sub>2</sub> allowances above the amount retained by OG&E and (ix) earn the most recent OCC authorized return on the unrecovered storm cost balance through the SCRR. On August 22, 2008, the OCC issued an order approving the settlement agreement and the SCRR was implemented in September 2008. In June 2008, OG&E wrote down the Red Rock deferred cost and the storm costs to their net present value, which resulted in a pre-tax charge of approximately \$9.0 million, which is currently included in Deferred Charges and Other Assets with an offset in Other Expense on the Company's Consolidated Financial Statements.

#### **OG&E Arkansas Rate Case Filing**

On August 29, 2008, OG&E filed with the APSC an application for an annual rate increase of approximately \$26.4 million to recover, among other things, costs for investments including the Redbud Facility and improvements in its system of power lines, substations and related equipment to ensure that OG&E can reliably meet growing customer demand for electricity, and a return on equity of 12.25 percent. In January 2009, the APSC Staff recommended a \$12.0 million rate increase based on a 10.5 percent return on equity. The Attorney General's consultant recommended a return on equity at the current authorized level of 10.0 percent and stated that his analysis identified at least \$10.9 million in reductions to OG&E's rate increase request. A hearing is scheduled for April 7, 2009. An order from the APSC is expected in June 2009 with new rates targeted for implementation in July 2009.

#### **OG&E 2009 Oklahoma Rate Case Filing**

Beginning in October 2008, OG&E began developing a rate case filing for the Oklahoma jurisdiction. On January 20, 2009, OG&E notified the OCC that it will make its planned Oklahoma rate case filing on or about February 26, 2009. OG&E is finalizing the preparation of the rate case and expects to request an increase of between \$100 million and \$110 million. The case is expected to proceed through the first half of 2009. If an increase is approved by the OCC, electric rates would likely be implemented in September 2009 at the earliest.

#### **OG&E Proposed Wind Power Project**

OG&E signed contracts on July 31, 2008 for approximately 101 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the future OU Spirit wind project in western Oklahoma. OG&E will seek regulatory recovery from the OCC and plans to have this project in-service by the end of 2009. Capital expenditures associated with this project are expected to be approximately \$260 million.

OG&E announced in October 2007 its goal to increase its wind power generation over the next four years from its 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. OG&E intends to add the new capacity to its power-generation portfolio no later than the end of 2010.

#### **Texas Panhandle/West Side Expansions**

In August 2006, Enogex completed a project to expand its gathering pipeline capacity in the Granite Wash play and Atoka play in the Wheeler County, Texas area of the Texas Panhandle that has allowed Enogex to benefit from growth opportunities in that marketplace. Since the pipeline was put in service, Enogex has completed the construction of five new gas gathering compressor stations totaling approximately 26,500 horsepower of compression, and several miles of gathering pipe, including a new 16-inch line that extends the original pipeline project an additional 20 miles to the west. Enogex is continuing to expand in the Wheeler and Hemphill counties in Texas and expects to add another 16,000 horsepower of low pressure compression to the Wheeler area by October 2009.

#### **Southeastern Oklahoma/East Side Expansions**

In February 2008, Enogex completed construction of a new 20-mile pipeline project that connects Enogex's Hughes, Coal and Pittsburgh county gathering system with the 30-inch Enogex mainline pipeline to Bennington, Oklahoma, and the 24-inch Enogex mainline pipeline to Wilburton, Oklahoma. The gathering project created additional gathering capacity of 75 million cubic feet per day ("MMcf/d") for customers desiring low-pressure services. The pipeline was complemented by approximately 16,000 horsepower of new gathering compression which was completed in the third quarter of 2008. Also, Enogex is planning to add approximately 16 miles of 20-inch steel pipe and 60 MMcf/d of additional treating facilities. Under the assumed operating conditions, the gathering pipe is expected to have throughput capacity of approximately 300 MMcf/d and is expected to be in service by June 2009. The capital expenditures associated with the additional pipe and treating facilities are expected to be approximately \$20 million.

### Enogex Additional Processing Capacity

Enogex will consider building or acquiring additional processing capacity in areas where the capacity is needed. Enogex completed construction of a new 100 MMcf/d refrigeration dew point conditioning plant in Roger Mills County of Oklahoma, which became operational in August 2008. In addition, Enogex is constructing a new 120 MMcf/d cryogenic plant equipped with electric compression near Clinton, Oklahoma. This plant will process new gas developing in the area and is expected to be in service by mid-2009. Also, Enogex has placed an order for a cryogenic processing plant that is scheduled for delivery in the fourth quarter of 2009, which is expected to add another 120 MMcf/d of processing capacity to Enogex's system.

### 2009 Outlook

The Company's 2009 earnings guidance remains unchanged at \$2.30 to \$2.60 per average diluted share. The Company currently projects 2009 earnings to be towards the lower half of the range primarily due to lower commodity prices in Enogex's business. The key factors and assumptions underlying this guidance are risk-adjusted to determine the ranges described below. Therefore, the ranges by component may not add to the total. The key factors and assumptions underlying this guidance have been updated to reflect current economic conditions and other developments. Management will monitor its assumptions throughout the year and will seek to take appropriate actions to offset any adverse change in its assumptions.

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

Key factors and assumptions for 2009 include:

#### Consolidated

- Between 96 million and 97 million average diluted shares outstanding;
- An effective tax rate of approximately 31 percent; and
- A projected loss at the holding company of between \$5 million and \$10 million, or \$0.05 to \$0.10 per diluted share, primarily due to interest expense relating to long and short-term debt borrowings.

#### OG&E

- Normal weather patterns are experienced for the year;
- Gross margin on weather-adjusted, retail electric sales increases approximately one percent;
- A reasonable regulatory outcome in the Oklahoma rate case with new rates in effect before the end of the third quarter of 2009;
- Arkansas annual rate increase of approximately \$12 million to \$14 million implemented in mid-2009;
- Storm cost recovery rider of approximately \$8 million to \$10 million;
- Operating expenses of approximately \$595 million to \$610 million;
- Interest expense of approximately \$95 million to \$98 million; and
- An effective tax rate of approximately 30 percent.

OG&E has significant seasonality in its earnings. OG&E typically shows minimal earnings or slight losses 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

Total Enogex anticipated gross margin of approximately \$335 million to \$375 million consisting of:

- Transportation and storage gross margin contribution of approximately \$145 million to \$155 million;
- Gathering and processing gross margin contribution of approximately \$190 million to \$220 million. Key factors affecting the gathering and processing gross margin forecast are:
  - Assumed increase of ten percent in gathered volumes over 2008;
  - Assumed natural gas prices of \$3.50 to \$4.13 per million British thermal unit ("MMBtu") in 2009;
  - Assumed realized commodity spreads of \$2.38 to \$2.91 per MMBtu in 2009. The realized commodity spread takes into account that 83 percent 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;
  - Assumed weighted average NGL prices of \$0.58 to \$0.79 per gallon in 2009;
  - Operating expenses of approximately \$215 million to \$225 million;
  - Interest expense of approximately \$35 million to \$40 million; and
  - An effective tax rate of approximately 39 percent.

The foregoing would result in estimated Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA") at Enogex of between \$190 million to \$220 million.

(In millions, year ended December 31)	2009
<b>Reconciliation of projected EBITDA to projected net cash provided from operating activities</b>	
Net cash provided by operating activities	\$155.0
Interest expense, net	37.0
Changes in operating working capital which provided (used) cash:	
Accounts receivable	(3.8)
Accounts payable	3.9
Other, including changes in noncurrent assets and liabilities	12.9
<b>EBITDA</b>	<b>\$205.0</b>
<b>Reconciliation of projected EBITDA to projected net income</b>	
Net Income	\$59.0
Add:	
Interest expense, net	37.0
Income tax expense	38.0
Depreciation and amortization	71.0
<b>EBITDA</b>	<b>\$205.0</b>

Based on midpoint of 2009 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 Measures" 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 65 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 our shareholder base, our financial position, our growth targets, the composition of our assets and investment opportunities. At the Company's December 2008 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 \$0.3550 per share from \$0.3475 per share effective with the Company's first quarter 2009 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, 2008, 2007 and 2006 and the Company's consolidated financial position at December 31, 2008 and 2007. 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)	2008	2007	2006
Operating income	\$ 462.1	\$ 455.3	\$ 432.7
Net income	\$ 231.4	\$ 244.2	\$ 262.1
Basic average common shares outstanding	92.4	91.7	91.0
Diluted average common shares outstanding	92.8	92.5	92.1
Basic earnings per average common share	\$ 2.50	\$ 2.66	\$ 2.88
Diluted earnings per average common share	\$ 2.49	\$ 2.64	\$ 2.84
Dividends declared per share	\$1.3975	\$1.3675	\$1.3375

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)	2008	2007	2006
<b>Operating income (loss) by business segment</b>			
OG&E (Electric Utility)	\$278.3	\$292.0	\$293.9
Enogex (Natural Gas Pipeline)			
Transportation and storage	67.8	55.0	54.7
Gathering and processing	117.4	91.4	79.8
OERI (Natural Gas Marketing) <sup>(A)</sup>	6.4	17.1	4.3
Other operations <sup>(B)</sup>	(7.8)	(0.2)	–
Consolidated operating income	\$462.1	\$455.3	\$432.7

<sup>(A)</sup> 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.

<sup>(B)</sup> 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)	2008	2007	2006
<b>OG&amp;E</b>			
Operating revenues	\$1,959.5	\$1,835.1	\$1,745.7
Cost of goods sold	1,114.9	1,025.1	950.0
Gross margin on revenues	844.6	810.0	795.7
Other operation and maintenance	351.6	320.7	316.5
Depreciation and amortization	155.0	141.3	132.2
Taxes other than income	59.7	56.0	53.1
Operating income	278.3	292.0	293.9
Interest income	4.4	–	1.9
Allowance for equity funds used during construction	–	–	4.1
Other income	3.6	5.0	4.0
Other expense	11.8	7.2	9.7
Interest expense	79.1	54.9	60.1
Income tax expense	52.4	73.2	84.8
Net income	\$ 143.0	\$ 161.7	\$ 149.3
Operating revenues by classification			
Residential	\$ 751.2	\$ 706.4	\$ 698.8
Commercial	479.0	450.1	428.3
Industrial	219.8	221.4	215.7
Oilfield	151.9	140.9	129.3
Public authorities and street light	190.3	181.4	171.0
Sales for resale	64.9	68.8	65.4
Provision for rate refund	(0.4)	0.1	(0.9)
System sales revenues	1,856.7	1,769.1	1,707.6
Off-system sales revenues	68.9	35.1	2.7
Other	33.9	30.9	35.4
Total operating revenues	\$1,959.5	\$1,835.1	\$1,745.7
MWH <sup>(A)</sup> sales by classification (in millions)			
Residential	9.0	8.7	8.7
Commercial	6.5	6.3	6.2
Industrial	4.0	4.2	4.4
Oilfield	2.9	2.8	2.7
Public authorities and street light	3.0	3.0	2.9
Sales for resale	1.4	1.4	1.5
System sales	26.8	26.4	26.4
Off-system sales	1.4	0.7	–
Total sales	28.2	27.1	26.4
Number of customers	770,088	762,234	754,840
Average cost of energy per KWH <sup>(B)</sup> (cents)			
Natural gas	8.455	6.872	6.829
Coal	1.153	1.143	1.114
Total fuel	3.337	3.173	3.003
Total fuel and purchased power	3.710	3.523	3.366
Degree days <sup>(C)</sup>			
Heating – Actual	3,394	3,175	2,746
Heating – Normal	3,650	3,631	3,631
Cooling – Actual	2,081	2,221	2,485
Cooling – Normal	1,912	1,911	1,911

<sup>(A)</sup> Megawatt-hour.

<sup>(B)</sup> Kilowatt-hour.

<sup>(C)</sup> 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.

## 2008 Compared to 2007

OG&E's operating income decreased approximately \$13.7 million in 2008 as compared to 2007 primarily due to higher operating expenses, 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.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. 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. This decrease was 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.

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 \$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:

- An increase of approximately \$9.5 million due to a correction of the over-capitalization of certain payroll, benefits, other employee related costs and overhead costs in previous years, as discussed in Note 14 of Notes to Consolidated Financial Statements;
- 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 \$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 services and approximately \$1.5 million in materials and supplies primarily attributable to overhaul expenses at several of OG&E's power plants;
- An increase of approximately \$5.3 million due to increased spending on vegetation management;
- An increase of approximately \$2.2 million in fleet transportation charges primarily due to higher fuel and maintenance costs; and
- An increase of approximately \$1.3 million in professional services expense primarily due to higher engineering consulting services during 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 costs 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 a 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. The increase was primarily due to additional assets, including the Redbud Facility, being placed into service in 2008 and amortization of the Arkansas storm costs that are currently recorded as a regulatory asset (see Note 1 of Notes to the Consolidated Financial Statements).

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 during 2008 and interest income from short-term investments.

*Other Income.* Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating 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 percent, primarily due to a lower gain on the guaranteed flat bill tariff due to warmer than normal weather with more customers participating in this plan.

*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 \$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. The increase in other expense was primarily due to:

- A write-down of deferred costs associated with the Red Rock power plant of approximately \$7.5 million; and
- A write-down of approximately \$1.5 million associated with the 2007 and 2006 storm costs related to a settlement with the OCC. See Note 16 of Notes to Consolidated Financial Statements for a discussion of these matters.

These increases in other expense were partially offset by a write-off of approximately \$3.1 million associated with the 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 January, September and December 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 during 2008 as compared to 2007 as well as a lower overall effective income tax rate primarily due to an increase in Federal renewable energy credits and additional state income tax credits in 2008 as compared 2007.

### 2007 Compared to 2006

OG&E's operating income decreased approximately \$1.9 million, or 0.7 percent, in 2007 as compared to 2006 primarily due to higher depreciation and amortization expense, higher taxes other than income and higher operation and maintenance expenses partially offset by a higher gross margin.

### Gross Margin

Gross margin was approximately \$810.0 million in 2007 as compared to approximately \$795.7 million in 2006, an increase of approximately \$14.3 million, or 1.8 percent. The gross margin increased primarily due to:

- Higher rates from the Centennial wind farm rider, security rider and Arkansas rate case, which increased the gross margin by approximately \$25.1 million;
- Increased demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by approximately \$9.4 million; and
- New customer growth in OG&E's service territory, which increased the gross margin by approximately \$9.1 million.

These increases in the gross margin were partially offset by:

- Cooler weather in OG&E's service territory resulting in an approximate 11 percent decrease in cooling degree days compared to 2006, which decreased the gross margin by approximately \$16.3 million; and
- Price variance due to sales and customer mix, which decreased the gross margin by approximately \$13.6 million.

Fuel expense was approximately \$756.1 million in 2007 as compared to approximately \$730.3 million in 2006, an increase of approximately \$25.8 million, or 3.5 percent, primarily due to increased natural gas generation in 2007 and a gain recognized from the sale of SO<sub>2</sub> allowances of approximately \$8.9 million in 2006. 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 2007, OG&E's fuel mix was 62 percent coal, 36 percent natural gas and two percent wind. In 2006, OG&E's fuel mix was 67 percent coal and 33 percent natural gas. Purchased power costs were approximately \$268.6 million in 2007 as compared to approximately \$219.7 million in 2006, an increase of approximately \$48.9 million, or 22.3 percent. This increase was primarily due to OG&E's entrance into the energy imbalance service market on February 1, 2007 (see Note 1 of Notes to Consolidated Financial Statements for a further discussion).

### Operating Expenses

Other operation and maintenance expenses were approximately \$320.7 million in 2007 as compared to approximately \$316.5 million in 2006, an increase of approximately \$4.2 million, or 1.3 percent. The increase in other operation and maintenance expenses was primarily due to:

- An increase in outside services expense of approximately \$12.9 million primarily due to planned overhaul expenses at the power plants;
- Higher salaries, wages and other employee benefits expense of approximately \$6.7 million; and
- An increase in fees and permits expense of approximately \$2.2 million due to additional fees to the SPP.

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

- An increase of capitalized work of approximately \$17.7 million primarily related to storm costs that were deferred as a regulatory asset in 2007; and
- A decrease of approximately \$2.2 million of an additional accrual due to a settlement of a claim in 2006.

Depreciation and amortization expense was approximately \$141.3 million in 2007 as compared to approximately \$132.2 million in 2006, an increase of approximately \$9.1 million, or 6.9 percent, primarily due to the Centennial wind farm being placed in service during January 2007.

Taxes other than income were approximately \$56.0 million in 2007 as compared to approximately \$53.1 million in 2006, an increase of approximately \$2.9 million, or 5.5 percent, primarily due to increased ad valorem tax accruals and increased payroll tax expenses.

### Additional Information

*Interest Income.* There was less than \$0.1 million of interest income in 2007. Interest income was approximately \$1.9 million in 2006. The decrease was primarily due to interest income earned on fuel under recoveries in 2006 while there was a fuel over recovery balance in 2007.

*Allowance for Equity Funds Used During Construction.* There was no allowance for equity funds used during construction in 2007 as compared to approximately \$4.1 million in 2006, a decrease of approximately \$4.1 million primarily due to construction costs for the Centennial wind farm that exceeded the average daily short-term borrowings in 2006.

*Other Income.* Other income was approximately \$5.0 million in 2007 as compared to approximately \$4.0 million in 2006, an increase of approximately \$1.0 million or 25.0 percent. The increase in other income was primarily due to an increase of approximately \$3.6 million related to the guaranteed flat bill tariff resulting from more customers participating in this plan, along with milder weather in 2007. This was partially offset by a decrease of approximately \$2.6 million associated with the tax gross up of allowance for equity funds used during construction in 2006 with no comparable item recorded in 2007.

*Other Expense.* Other expense was approximately \$7.2 million in 2007 as compared to approximately \$9.7 million in 2006, a decrease of approximately \$2.5 million, or 25.8 percent, primarily due to a loss on the retirement of fixed assets of approximately \$5.2 million in 2006 partially offset by the write-off of non-recoverable Red Rock expenses of approximately \$3.1 million for Arkansas and the FERC jurisdictions in 2007.

*Interest Expense.* Interest expense was approximately \$54.9 million in 2007 as compared to \$60.1 million in 2006, a decrease of approximately \$5.2 million, or 8.7 percent. The decrease in interest expense was primarily due to:

- A settlement with the IRS resulting in a reversal of interest expense of approximately \$7.2 million in 2007; and
- A decrease of approximately \$7.0 million associated with the interest from a water storage facility in 2006.

These decreases in interest expense were partially offset by:

- An increase of approximately \$3.5 million in interest to OGE Energy;
- An increase of approximately \$1.7 million associated with the carrying charges in the over recovery on fuel from customers; and
- An increase of approximately \$1.7 million due to interest expense recorded on 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 \$73.2 million in 2007 as compared to approximately \$84.8 million in 2006, a decrease of approximately \$11.6 million, or 13.7 percent, primarily due to renewable energy tax credits for which OG&E became eligible in 2007 on the wind power production from OG&E's Centennial wind farm partially offset by higher pre-tax income for OG&E.

## Enogex – Continuing Operations

(In millions, year ended December 31)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
<b>2008</b>					
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
<b>2007</b>					
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
<b>2006</b>					
Operating revenues	\$508.7	\$ 704.3	\$1,941.3	\$(786.5)	\$2,367.8
Cost of goods sold	383.1	536.7	1,927.1	(786.5)	2,060.4
Gross margin on revenues	125.6	167.6	14.2	–	307.4
Other operation and maintenance	41.2	59.5	9.3	–	110.0
Depreciation and amortization	17.9	24.2	0.2	–	42.3
Impairment of assets	–	0.3	–	–	0.3
Taxes other than income	11.8	3.8	0.4	–	16.0
Operating income	\$ 54.7	\$ 79.8	\$ 4.3	\$ –	\$ 138.8

## Operating Data – Continuing Operations

Year Ended December 31	2008	2007	2006
New well connects – includes wells behind central receipt points <sup>(A)</sup>	357	374	362
New well connects – excludes wells behind central receipt points	203	178	206
Gathered volumes – (TBtu/d) <sup>(B)</sup>	1.16	1.05	0.98
Incremental transportation volumes (TBtu/d)	0.41	0.47	0.46
Total throughput volumes (TBtu/d)	1.57	1.52	1.44
Natural gas processed (TBtu/d)	0.66	0.57	0.54
Natural gas liquids sold – keep-whole (million gallons)	181	252	244
Natural gas liquids sold – purchased for resale (million gallons)	222	117	113
Natural gas liquids sold – percent-of-liquids (million gallons)	23	16	14
Total natural gas liquids sold (million gallons)	426	385	371
Average sales price per gallon	\$1.255	\$1.048	\$0.902
Estimated realized keep-whole spreads <sup>(C)</sup>	\$ 6.15	\$ 5.35	\$ 3.99

<sup>(A)</sup> Includes wells behind central receipt points (as reported to management by third parties). A central receipt point is a single receipt point into a gathering line where a producer aggregates the volumes from one or more wells and delivers them into the gathering system at a single meter site.

<sup>(B)</sup> Incremental transportation volumes (reported in trillion British thermal units per day) consist of natural gas moved only on the transportation pipeline.

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

## 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 and natural gas length 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 commodity spreads throughout the majority of 2008, which increased the gross margin by approximately \$18.6 million;
- Increased condensate margin associated with the processing operations due to higher prices and a 15.8 percent increase in volumes in 2008 as compared to 2007, which increased the gross margin by approximately \$17.1 million;

- Increased percent-of-liquids gross margin associated with the processing operations due to: (i) favorable pricing for NGLs, as well as a 28.3 percent increase in volumes retained by Enogex, which increased the gross margin by approximately \$10.8 million and (ii) new volumes from the Atoka joint venture 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 the Atoka joint venture, 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 and natural gas length 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 \$3.5 million.

#### Operating Expenses

The aggregate of other operation and maintenance expenses, depreciation and amortization expense, impairment of assets and taxes other than income was approximately \$18.2 million higher in 2008 as compared to 2007. The variances in depreciation and amortization expense on both a consolidated basis and by segment reflects increased levels of depreciable plant in service during 2008. The \$8.1 million increase in other operation and maintenance expenses on a consolidated basis was primarily due to an increase in expenses for non-capitalized system projects, an increase in salaries, wages and benefits and increased allocations for overhead costs from OGE Energy and administrative service fees from OERI in 2008 as compared to 2007.



Specifically, by segment, other operation and maintenance expenses for the transportation and storage business were 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 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 increases 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 expenses for the gathering and processing business were 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.

*Other Expense.* Enogex's consolidated other expense was approximately \$7.5 million in 2008 as compared to approximately \$2.3 million in 2007, an increase of approximately \$5.2 million primarily due to an increase in the minority interest in the earnings of the Atoka joint venture, which began operations in August 2007.

*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.

#### 2007 Compared to 2006

Enogex's operating income increased approximately \$24.7 million in 2007 as compared to 2006 primarily due to a higher gross margin in each of Enogex's segments, which was partially offset by higher operating expenses and higher depreciation and amortization expense.

#### Gross Margin

Enogex's consolidated gross margin increased approximately \$45.7 million in 2007 as compared to 2006. The increase resulted from a \$28.3 million higher gross margin in the gathering and processing business, a \$7.1 million higher gross margin in the transportation and storage business and \$13.6 million higher gross margin in the marketing business.

The transportation and storage business contributed approximately \$132.7 million of Enogex's consolidated gross margin in 2007 as compared to approximately \$125.6 million in 2006, an increase of approximately \$7.1 million, or 5.7 percent. The transportation operations contributed approximately \$97.8 million of Enogex's consolidated gross margin in 2007. The storage operations contributed approximately \$34.9 million of Enogex's consolidated gross margin in 2007. The transportation and storage gross margin increased primarily due to:

- A reduction in the lower of cost or market adjustments related to natural gas inventories used to operate the pipeline in 2006, which reduced the 2006 gross margin by approximately \$8.3 million for which there was no comparable item in 2007;
- Increased storage demand fees due to entering into new contracts in 2007 with more favorable terms, which increased the gross margin by approximately \$7.8 million;
- A change in Enogex's over-recovered position in its transportation business to an under-recovered position under its FERC-approved fuel tracker in the East Zone in 2007 as compared to 2006, which increased the gross margin by approximately \$2.6 million;
- The liability associated with a throughput contract which was transferred to the gathering and processing segment in the second quarter of 2007, which increased the gross margin by approximately \$2.4 million; and
- Lower electric compression expense associated with its transportation business due to the decreased use of electric compression at Enogex's Harrah processing plant following the loss of a contract during the second quarter of 2007, which increased the gross margin by approximately \$1.3 million.

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

- An increased imbalance liability, net of fuel recoveries and natural gas length positions, in its transportation business in 2007, which decreased the gross margin by approximately \$6.7 million;
- A decrease in the net gas sales margin in its transportation business due to a decrease in natural gas prices in 2007, which decreased the gross margin by approximately \$3.3 million;
- Decreased commodity, interruptible and low and high pressure revenues in its transportation business of approximately \$2.2 million in 2007 due primarily to renegotiation of contracts to demand-based contracts rather than commodity-based contracts in 2007; and
- Decreased commodity and interruptible revenues of approximately \$1.1 million in 2007 due primarily to an interruptible storage contract that expired on September 30, 2006.

The gathering and processing business contributed approximately \$195.9 million of Enogex's consolidated gross margin in 2007 as compared to approximately \$167.6 million in 2006, an increase of approximately \$28.3 million, or 16.9 percent. The gathering operations contributed approximately \$89.4 million of Enogex's consolidated gross margin in 2007. The processing operations contributed approximately \$106.5 million of Enogex's consolidated gross margin in 2007. The gathering and processing gross margin increased primarily due to:

- An increase in keep-whole margins associated with the processing operations in 2007 as compared to 2006 primarily due to higher commodity spreads, which increased the gross margin by approximately \$6.7 million;
- Reduced imbalance expense associated with its gathering operations resulting from the recognition in 2006 of an approximately \$3.2 million imbalance liability upon the transfer of imbalances previously recognized in the transportation and storage business coupled with a decrease of an approximately \$3.4 million imbalance liability, net of fuel recoveries and natural gas length positions, in 2007 as compared to 2006, which increased the gross margin by approximately \$6.6 million;
- Increased condensate margin associated with its processing operations due to higher prices in 2007 as compared to 2006, which increased the gross margin by approximately \$4.6 million;
- Renegotiated percent-of-liquids contracts associated with its processing operations entered into during 2007, which increased the gross margin by approximately \$3.7 million;
- Higher fees associated with its gathering operations from low pressure contracts renegotiated with more favorable terms in 2007, which increased the gross margin by approximately \$2.5 million;
- Sales of residue gas associated with its processing operations retained from the Atoka processing plant, which began operations in August 2007, that increased the gross margin by approximately \$2.2 million;
- Higher compression fees associated with its gathering operations resulting from new business in 2007, which increased the gross margin by approximately \$2.0 million;
- An increase in new gathering business during 2007, which increased the gross margin by approximately \$1.8 million; and

- Increased high pressure volumes associated with its gathering operations due to new production in 2007, which increased the gross margin by approximately \$1.7 million.

These increases in the gathering and processing gross margin were partially offset by the settlement on a throughput contract in 2007 associated with its processing operations, which decreased the gross margin by approximately \$1.9 million.

The marketing business contributed approximately \$27.8 million of Enogex's consolidated gross margin in 2007 as compared to approximately \$14.2 million in 2006, an increase of approximately \$13.6 million, or 95.8 percent. The marketing gross margin increased primarily due to:

- Realized gains from physical activity on a transportation contract, which increased the gross margin by approximately \$32.7 million;
- A reduction in lower of cost or market adjustments related to natural gas held in storage in 2007 as compared to 2006, which increased the gross margin by approximately \$6.6 million;
- Gains on physical sales of natural gas storage inventory activity partially offset by higher fees, which increased the gross margin by approximately \$2.9 million; and
- Increased gains from origination and other marketing and trading activity in 2007, which increased the gross margin by approximately \$1.3 million.

These increases in the marketing gross margin were partially offset by:

- Lower gains on economic hedges of natural gas storage inventory from recording these hedges at market value on December 31, 2007 as compared to December 31, 2006, which decreased the gross margin by approximately \$17.0 million; and
- Lower gains on economic hedges associated with various transportation contracts from recording these hedges at market value on December 31, 2007 as compared to December 31, 2006, which decreased the gross margin by approximately \$12.9 million.

#### Operating Expenses

The aggregate of other operation and maintenance expenses, depreciation and amortization expense, impairment of assets and taxes other than income was approximately \$21.0 million higher in 2007 as compared to 2006. The variances in depreciation and amortization expense and in taxes other than income on both a consolidated basis and by segment reflect differing levels of depreciable plant in service and a slight decrease in property taxes. The \$17.4 million increase in other operation and maintenance expenses on a consolidated basis was primarily due to:

- Higher salaries, wages and other employee benefits due to higher incentive compensation and hiring additional employees;
- An increase in outside services, materials and supplies expense and office expense due to an increase in system projects in 2007; and
- A sales and use tax refund received in the prior year.

Specifically, by segment, other operation and maintenance expenses for the transportation and storage business were approximately \$7.3 million, or 17.7 percent, higher in 2007 as compared to 2006 primarily due to:

- Higher salaries, wages and other employee benefits expense of approximately \$5.4 million primarily due to higher incentive compensation and hiring additional employees to support business growth;
- An increase of approximately \$4.7 million in outside services, materials and supplies expense and office expense due to an increase in system projects in 2007;
- An increase of approximately \$3.3 million due to a fee the marketing business began charging the transportation and storage business in 2007 related to hedging activities;
- Higher allocations from OGE Energy for overhead costs of approximately \$2.1 million; and
- An increase in professional services expense of approximately \$1.2 million for legal and consultant costs for exploration of business expansion in 2007.

These increases were partially offset by:

- Higher internal allocations to the other Enogex segments for overhead costs of approximately \$5.9 million; and
- A decrease of approximately \$1.2 million in rental expense due to the renegotiation of an office building lease in 2007 in addition to the expiration of a building lease in June 2006.

Other operation and maintenance expenses for the gathering and processing business were approximately \$12.6 million, or 21.2 percent, higher in 2007 as compared to 2006 primarily due to:

- Higher allocations from the transportation and storage business and OGE Energy of approximately \$6.8 million primarily due to increased costs in 2007;
- A sales and use tax refund of approximately \$2.0 million received in May 2006 related to activity in prior years with no corresponding item in 2007;
- An increase of approximately \$1.7 million in materials and supplies expense primarily due to an increase in system projects in 2007;
- An increase of approximately \$1.3 million in higher salaries, wages and other employee benefits expense primarily due to hiring additional employees to support business growth; and
- An increase of approximately \$1.0 million in higher compressor rental costs resulting from new business in 2007.

Other operation and maintenance expenses for the marketing business were approximately \$0.8 million, or 8.6 percent, higher in 2007 as compared to 2006 primarily due to higher allocations of approximately \$1.5 million primarily due to increased costs in 2007.

#### Enogex Consolidated Information

*Interest Income.* Enogex's consolidated interest income was approximately \$9.2 million in 2007 as compared to approximately \$11.1 million in 2006, a decrease of approximately \$1.9 million, or 17.1 percent, primarily due to interest income earned on cash investments from the cash proceeds from the sale of certain gas gathering assets in the Kinta, Oklahoma area (the "Kinta Assets") in May 2006.

*Other Income.* Enogex's consolidated other income was approximately \$0.9 million in 2007 as compared to approximately \$7.7 million in 2006, a decrease of approximately \$6.8 million, or 88.3 percent. The decrease was primarily due to:

- A pre-tax litigation settlement of approximately \$5.2 million in 2006;
- A pre-tax gain of approximately \$1.0 million in the fourth quarter of 2006 from the sale of certain west Texas pipeline assets; and
- A pre-tax gain of approximately \$0.5 million in the first quarter of 2006 from the sale of small gathering sections of Enogex's pipeline.

*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 2006, Enogex's consolidated net income, including the discontinued operations discussed below under the caption "Enogex – Discontinued Operations," was approximately \$113.5 million, which included a loss of approximately \$6.3 million resulting from recording natural gas storage inventory held by OERI at the lower of cost or market value on December 31, 2006. The offsetting gains from the sale of withdrawals from inventory were realized during the first three months of 2007. Also, in 2006, Enogex had an increase in net income of approximately \$41.2 million relating to various items that Enogex does not consider to be reflective of its ongoing performance. These increases in consolidated net income include:

- An after-tax gain on the sale of the Kinta Assets in the second quarter of 2006 of approximately \$34.1 million;
- The approximately \$3.2 million after-tax impact of a litigation settlement;
- Income from discontinued operations of approximately \$1.9 million;
- A sales and use tax refund related to activity in prior years of approximately \$1.3 million after tax;
- An after-tax gain of approximately \$0.6 million related to the sale of certain west Texas pipeline assets; and
- An after-tax gain of approximately \$0.3 million from the sale of a small gathering section of Enogex's pipeline.

These increases in net income were partially offset by a decrease in net income of approximately \$0.2 million, related to an impairment of certain long-lived assets.

<small>(In millions, year ended December 31)</small>	<b>2008</b>	2007
<b>OERI</b>		
Operating revenues	<b>\$1,529.4</b>	\$1,541.2
Cost of goods sold	<b>1,509.5</b>	1,513.4
Gross margin on revenues	<b>19.9</b>	27.8
Other operation and maintenance	<b>12.9</b>	10.1
Depreciation and amortization	<b>0.2</b>	0.2
Taxes other than income	<b>0.4</b>	0.4
Operating income	<b>\$ 6.4</b>	\$ 17.1

## 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 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, which decreased the gross margin by approximately \$6.8 million;
- A lower of cost or market adjustment of approximately \$6.2 million for natural gas storage inventory at December 31, 2008 as compared to a lower of cost or market adjustment of approximately \$3.6 million at December 31, 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 of storage 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 a 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 Measures

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

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

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

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

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

(In millions, year ended December 31)	2008	2007
<b>Reconciliation of EBITDA to net cash provided from operating activities</b>		
Net cash provided from operating activities <sup>(A)</sup>	\$242.0	\$107.8
Interest expense, net	30.2	22.4
Changes in operating working capital which provided (used) cash:		
Accounts receivable	(24.8)	(0.8)
Accounts payable	(28.5)	(5.0)
Other, including changes in noncurrent assets and liabilities	14.4	83.6
EBITDA <sup>(B)</sup>	\$233.3	\$208.0
<b>Reconciliation of EBITDA to net income</b>		
Net income <sup>(C)</sup>	\$ 91.2	\$ 86.2
Add:		
Interest expense, net	30.2	22.4
Income tax expense	57.3	53.5
Depreciation and amortization	54.6	45.9
EBITDA	\$233.3	\$208.0

<sup>(A)</sup> Approximately \$10.7 million of OERI's net cash used by operating activities is included in the net cash provided by operating activities in 2007.

<sup>(B)</sup> Approximately \$17.4 million of EBITDA in 2007 was attributable to OERI.

<sup>(C)</sup> Approximately \$10.9 million of net income in 2007 was attributable to OERI.

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

### Enogex – Discontinued Operations

In May 2006, Enogex's wholly owned subsidiary, Enogex Gas Gathering LLC, sold the Kinta Assets, which included approximately 568 miles of gathering pipeline and 22 compressor units, for approximately \$92.9 million. Enogex recorded an after tax gain of approximately \$34.1 million from this sale in the second quarter of 2006.

The Consolidated Financial Statements of the Company have been reclassified to reflect the above sale as a discontinued operation. Accordingly, revenues, costs and expenses and cash flows from this sale have been excluded from the respective captions in the Consolidated Financial Statements and have been separately reported as discontinued operations in the applicable financial statement captions. As the above sale occurred prior to 2007, there are no results of operations for discontinued operations during 2007 and 2008. Results for these discontinued operations are summarized and discussed below.

(In millions, year ended December 31)	2008	2007	2006
Operating revenues	\$ –	\$ –	\$ 9.4
Cost of goods sold	–	–	4.9
Gross margin on revenues	–	–	4.5
Other operation and maintenance	–	–	1.0
Depreciation and amortization	–	–	0.3
Taxes other than income	–	–	0.1
Operating income	–	–	3.1
Interest income	–	–	–
Other income	–	–	56.0
Other expense	–	–	–
Interest expense	–	–	–
Income before taxes	–	–	59.1
Income tax expense	–	–	23.1
Net income	\$ –	\$ –	\$36.0

### 2007 Compared to 2006

Following the sale of the Kinta Assets in May 2006, no operations of the Kinta Assets are reflected in the Consolidated Financial Statements.

### Financial Condition

The balance of Cash and Cash Equivalents was approximately \$174.4 million and \$8.8 million at December 31, 2008 and 2007, respectively, an increase of approximately \$165.6 million primarily due to the need for the Company to have adequate liquidity due to the volatility of the commercial paper and capital markets.

The balance of Accounts Receivable was approximately \$288.1 million and \$334.4 million at December 31, 2008 and 2007, respectively, a decrease of approximately \$46.3 million, or 13.8 percent, primarily due to a decrease in natural gas prices and volumes at OERI partially offset by an increase in OG&E's billings to its customers and increased rates from the Redbud Facility rider and storm cost recovery rider.

The balance of Accumulated Deferred Tax Assets was approximately \$14.9 million and \$38.1 million at December 31, 2008 and 2007, respectively, a decrease of approximately \$23.2 million, or 60.9 percent, primarily due to a change in the position of the Company's deferred hedging activities during 2008.

The balance of Property, Plant and Equipment in Service was approximately \$7.7 billion and \$6.8 billion at December 31, 2008 and 2007, respectively, an increase of approximately \$0.9 billion, or 13.2 percent, primarily due to the purchase of the Redbud Facility as well as other projects for transmission and distribution at OG&E and various gathering and transportation projects at Enogex.

The balance of Construction Work in Process was approximately \$399.0 million and \$179.8 million at December 31, 2008 and 2007, respectively, an increase of approximately \$219.2 million primarily due to costs associated with the OU Spirit wind project in western Oklahoma for OG&E and various transportation, gathering and processing projects at Enogex.

The balance of Regulatory Asset – SFAS No. 158 was approximately \$344.7 million and \$174.6 million at December 31, 2008 and 2007, respectively, an increase of approximately \$170.1 million or 97.4 percent. The increase was primarily due to an increase in the pension plan, restoration of retirement income plan and postretirement benefit plan obligations due to a decrease in the fair value of plan assets in 2008.

The balance of non-current Price Risk Management Assets was approximately \$22.0 million and \$0.3 million at December 31, 2008 and 2007, respectively, an increase of approximately \$21.7 million, primarily due to NGLs and keep-whole hedges moving from a liability to an asset due to a decrease in NGL spreads in 2008.

The balance of Other Deferred Charges was approximately \$63.2 million and \$85.6 million at December 31, 2008 and 2007, respectively, a decrease of approximately \$22.4 million, or 26.2 percent, primarily due to write-downs of the deferred costs associated with the cancellation of the Red Rock power plant project and 2007 ice storm costs and amortization of the regulatory asset for deferred pension costs.

The balance of Accounts Payable was approximately \$279.7 million and \$399.3 million at December 31, 2008 and 2007, respectively, a decrease of approximately \$119.6 million, or 30.0 percent, primarily due to timing of outstanding checks clearing the bank, payments made in the first quarter of 2008 for the December 2007 ice storm, a decrease in the payable for gas purchases for OG&E and a decrease in volumes purchased from third parties at OERI.

The balance of current Price Risk Management Liabilities was approximately \$2.3 million and \$20.6 million at December 31, 2008 and 2007, respectively, a decrease of approximately \$18.3 million, or 88.8 percent, primarily due to a decrease in NGL spreads in 2008.

The balance of Other Current Liabilities was approximately \$62.2 million and \$38.2 million at December 31, 2008 and 2007, respectively, an increase of approximately \$24.0 million, or 62.8 percent, primarily due to an accrual for a margin payment to an OERI counterparty, an increase in the weighted-average cost of inventory valuation under a certain storage agreement at OERI and an increase in the liability for the OG&E off-system sales credit to other utilities and power marketers.

The balance of Long-Term Debt was approximately \$2.2 billion and \$1.3 billion at December 31, 2008 and 2007, respectively, an increase of approximately \$0.9 billion, or 69.2 percent, primarily due to borrowings by Enogex under its revolving credit agreement in the third quarter of 2008 and the issuance of long-term debt by OG&E in January, September and December 2008.

The balance of Accrued Benefit Obligations was approximately \$350.5 million and \$156.2 million at December 31, 2008 and 2007, respectively, an increase of approximately \$194.3 million, primarily due to plan changes for prior service cost and net loss for the pension plan, restoration of retirement income plan and postretirement benefit plan partially offset by pension plan contributions in 2008.

The balance of Accumulated Deferred Income Taxes was approximately \$996.9 million and \$853.6 million at December 31, 2008 and 2007, respectively, an increase of approximately \$143.3 million, or 16.8 percent, primarily due to accelerated bonus tax depreciation which resulted in higher Federal and state deferred tax accruals.

The balance of Accumulated Other Comprehensive Loss was approximately \$13.7 million and \$81.0 million at December 31, 2008, and 2007, respectively, a decrease of approximately \$67.3 million, or 83.1 percent, primarily due to hedging gains at Enogex partially offset by plan changes for prior service cost and net loss for the pension plan, restoration of retirement income plan and postretirement benefit plan.

#### **Off-Balance Sheet Arrangements**

Off-balance sheet arrangements include any transactions, agreements or other contractual arrangements to which an unconsolidated entity is a party and under which the Company has: (i) any obligation under a guarantee contract having specific characteristics as defined in Financial Accounting Standards Board ("FASB") Interpretation ("FIN") No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"; (ii) a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to such entity for such assets; (iii) any obligation, including a contingent obligation, under a contract that would be accounted for as a derivative instrument but is indexed to the Company's own stock and is classified in stockholders' equity in the Company's consolidated balance sheet; or (iv) any obligation, including a contingent obligation, arising out of a variable interest as defined in FIN No. 46, "Consolidation of Variable

Interest Entities, an interpretation of Accounting Research Bulletin No. 51," in an unconsolidated entity that is held by, and material to, the Company, where such entity provides financing, liquidity, market risk or credit risk support to, or engages in leasing, hedging or research and development services with, the Company. The Company has the following material off-balance sheet arrangements.

#### **OG&E Railcar Lease Agreement**

At December 31, 2007, OG&E had a noncancellable operating lease with purchase options, covering 1,409 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. In April 2008, OG&E amended its contract to add 55 new railcars for approximately \$3.5 million. At the end of the new 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. See Note 15 of Notes to Consolidated Financial Statements for a further discussion.

#### **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. However, OGE Energy's and OG&E's ability to access the commercial paper market was adversely impacted by the market turmoil that began in September 2008. Accordingly, in order to ensure the availability of funds, OGE Energy and OG&E utilized borrowings under their revolving credit agreements, which generally bear a higher interest rate and a minimum 30-day maturity compared to commercial paper, which has historically been available at lower interest rates and on a daily basis. However, in late 2008, OGE Energy's and OG&E's revolving credit borrowings had a lower interest rate than commercial paper due to disruptions in the credit markets. In December 2008, OG&E repaid the outstanding borrowings under its revolving credit agreement with a portion of the proceeds received from the issuance of long-term debt in December. OG&E intends to utilize commercial paper in the commercial paper market when available. OGE Energy expects to repay the borrowings under its revolving credit agreement and begin utilizing the commercial paper market when available.

Capital requirements and future contractual obligations estimated for the next five years and beyond are as follows:

(In millions)	Total	Less than 1 year (2009)	1 – 3 years (2010 – 2011)	3 – 5 years (2012 – 2013)	More than 5 years
OG&E capital expenditures including AFUDC <sup>(A)</sup>	\$2,736.5	\$ 611.5	\$ 865.8	\$ 825.5	\$ 433.7
Enogex capital expenditures including capitalized interest	980.0	230.0	300.0	300.0	150.0
Other operations capital expenditures	382.3	30.5	108.6	219.6	23.6
Total capital expenditures	4,098.8	872.0	1,274.4	1,345.1	607.3
Maturities of long-term debt	2,165.3	–	400.0	120.0	1,645.3
Interest payments on long-term debt	1,739.3	143.9	233.5	213.1	1,148.8
Pension funding obligations	190.0	50.0	70.0	70.0	–
Total capital requirements	8,193.4	1,065.9	1,977.9	1,748.2	3,401.4
Operating lease obligations					
OG&E railcars	45.7	3.9	41.8	–	–
Enogex noncancellable operating leases	8.7	4.2	4.1	0.4	–
Total operating lease obligations	54.4	8.1	45.9	0.4	–
Other purchase obligations and commitments					
OG&E cogeneration capacity payments	416.9	86.8	168.1	162.0	N/A
OG&E fuel minimum purchase commitments	527.3	320.7	179.3	7.8	19.5
Other	36.2	5.4	10.8	11.9	8.1
Total other purchase obligations and commitments	980.4	412.9	358.2	181.7	27.6
Total capital requirements, operating lease obligations and other purchase obligations and commitments	9,228.2	1,486.9	2,382.0	1,930.3	3,429.0
Amounts recoverable through fuel adjustment clause <sup>(B)</sup>	(989.9)	(411.4)	(389.2)	(169.8)	(19.5)
Total, net	\$8,238.3	\$1,075.5	\$1,992.8	\$1,760.5	\$3,409.5

<sup>(A)</sup> Under current environmental laws and regulations, OG&E may be required to spend approximately \$110 million in capital expenditures on its power plants related to regional haze projects. Until the compliance plan is approved as discussed below, the total cost of compliance, including capital expenditures, cannot be estimated by OG&E with a reasonable degree of certainty.

<sup>(B)</sup> Includes expected recoveries of costs incurred for OG&E's railcar operating lease obligations and OG&E's unconditional fuel purchase obligations.

N/A – not available

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.

### 2008 Capital Requirements and Financing Activities

Total capital requirements, consisting of capital expenditures, maturities of long-term debt, interest payments on long-term debt and pension funding obligations, were approximately \$1,377.2 million and contractual obligations, net of recoveries through fuel adjustment clauses, were approximately \$8.6 million resulting in total net capital requirements and contractual obligations of approximately \$1,385.8 million in 2008. Approximately \$4.4 million of the 2008 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately \$676.5 million and net contractual obligations of approximately \$9.7 million totaling approximately \$686.2 million in 2007, of which approximately \$9.3 million was to comply with

environmental regulations. During 2008, the Company's sources of capital were cash generated from operations and long-term borrowings. 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.

### Issuance of Long-Term Debt

In January 2008, OG&E issued \$200 million of 6.45% senior notes due February 1, 2038. The proceeds from the issuance were used to repay commercial paper borrowings.

On April 1, 2008, Enogex entered into a \$250 million unsecured five-year revolving credit facility. Subject to certain limitations, the facility provides Enogex with the option, exercisable annually, to extend the maturity of the facility for an additional year and, upon the expiration of the revolving term, an option to convert the outstanding balance under the facility to a one-year term loan. The facility provides the option for Enogex to increase the borrowing limit by up to an additional \$250 million (to a maximum of \$500 million) upon the agreement of the lenders (or any additional lender) and the satisfaction of other specified conditions. At December 31, 2008, there was \$120.0 million outstanding under the facility. These borrowings are not expected to be repaid within the next 12 months, therefore, they are classified as long-term debt for financial reporting purposes.

In September 2008, OG&E issued \$250 million of 6.35% senior notes due September 1, 2018. The proceeds from the issuance were used to fund a portion of the acquisition of the Redbud Facility. Pending such use, the proceeds were used to temporarily repay a portion of OG&E's outstanding commercial paper borrowings, as well as short-term borrowings from OGE Energy, both of which were incurred in part to fund OG&E's daily operational needs.

In December 2008, OG&E issued \$250 million of 8.25% senior notes due January 15, 2019. The proceeds from the issuance were used to repay borrowings under OG&E's term loan agreement with UBS AS, Stamford Branch and UBS Securities LLC, as discussed in Note 12 of Notes to Consolidated Financial Statements, and the Company's and OG&E's revolving credit agreements, which were used to fund OG&E's daily operational needs as well as OG&E's acquisition of the Redbud Facility.

### Long-Term Debt Maturities

Other than the January 2010 maturity of Enogex's long-term debt discussed below, there are no maturities of the Company's long-term debt during 2010. Also, there are no maturities of the Company's long-term debt in years 2009, 2011 or 2012. Other than any outstanding balance under Enogex's revolving credit facility, which matures in 2013, there are no maturities of the Company's long-term debt during 2013. At December 31, 2008, there was \$120.0 million outstanding under Enogex's revolving credit facility.

At December 31, 2008, the Company had approximately \$174.4 million of cash on hand. At December 31, 2008, the Company had approximately \$816.7 million of net available liquidity under its revolving credit agreements.

### Cash Flows

(In millions, year ended December 31)	2008	2007	2006
Net cash provided from operating activities	\$ 625.0	\$ 328.5	\$ 569.5
Net cash used in investing activities	(1,184.1)	(556.3)	(483.5)
Net cash provided from (used in) financing activities	724.7	188.7	(137.4)

The increase of approximately \$296.5 million in net cash provided from operating activities in 2008 as compared to 2007 was primarily due to: (i) a decrease in accounts payable due to payments in the first quarter of 2008 related to the December 2007 ice storm and a decrease in volumes purchased from third parties at OERI, (ii) an increase in price risk management assets and liabilities due to net cash collateral received from counterparties related to the Company's existing derivative positions, (iii) an increase in fuel clause recoveries due to higher fuel recoveries in 2008 as compared to 2007 and (iv) an increase in accounts receivable at OERI primarily due to a decrease in natural gas prices and volumes partially offset by a decrease at OG&E due to higher billed sales in 2008. The reduction of approximately \$241.0 million in

net cash provided from operating activities in 2007 as compared to 2006 was primarily related to lower fuel recoveries from OG&E customers partially offset by changes to other working capital.

The increase of approximately \$627.8 million in net cash used in investing activities in 2008 as compared to 2007 related to higher level of capital expenditures primarily related to the purchase of the Redbud Facility and a higher level of capital expenditures at Enogex. The increase of approximately \$72.8 million in net cash used in investing activities in 2007 as compared to 2006 related to higher levels of capital expenditures.

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 issuance of long-term debt in January, September and December 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. The increase of approximately \$326.1 million in net cash provided from financing activities in 2007 as compared to 2006 primarily related to higher levels of short-term debt partially offset by reduced amounts related to the issuance of long-term debt.

### Future Capital Requirements and Financing Activities

#### Capital Expenditures

The Company's current 2009 to 2014 construction program includes continued investment in OG&E's distribution, generation and transmission system and Enogex's transportation, storage, gathering and processing assets. The Company's current estimates of capital expenditures, are approximately: 2009 – \$872.0 million, 2010 – \$593.4 million, 2011 – \$681.0 million, 2012 – \$652.8 million, 2013 – \$692.3 million and 2014 – \$607.3 million. These capital expenditures include expenditures related to: (i) the proposed transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma, (ii) OGE Energy's portion of the proposed transmission projects as part of a newly formed transmission joint venture, (iii) OG&E's proposed 101 MW OU Spirit wind power project in western Oklahoma, (iv) OG&E's proposed system hardening plan and (v) OG&E's transmission/substation SPP project (see Note 16 of Notes to Consolidated Financial Statements for a further discussion). These capital expenditures exclude any environmental expenditures associated with Best Available Retrofit Technology ("BART") requirements. As discussed in Note 15 of Notes to Consolidated Financial Statements, due to comments from the U.S. Environmental Protection Agency ("EPA") that OG&E's proposed initial BART compliance plan would not satisfy the applicable requirements, OG&E completed additional analysis. On May 30, 2008, OG&E filed the results with the Oklahoma Department of Environmental Quality ("ODEQ") for the affected generating units. In the May 30, 2008 filing, OG&E indicated its intention to install low nitrogen oxide ("NOX") combustion technology at its affected generating stations and to continue to burn low sulfur coal at its four coal-fired generating units at its Muskogee and Sooner generating stations. The capital expenditures associated with the installation of the low NOX combustion technology are expected



to be approximately \$110 million. OG&E believes that these control measures will achieve visibility improvements in a cost-effective manner. OG&E did not propose the installation of scrubbers at its four coal-fired generating units because OG&E concluded that, consistent with the EPA's regulations on BART, the installation of scrubbers (at an estimated cost of \$1.7 billion) would not be cost-effective. OG&E previously reported an expectation that a compliance plan would be approved by the EPA by December 31, 2008; however, submission of the overall compliance plan by the ODEQ (which will include OG&E's compliance plan previously submitted to the ODEQ) has been delayed and the current timing of the EPA approval cannot be reasonably predicted. In a letter dated November 4, 2008, the EPA notified the ODEQ that they had completed their review of BART applications for all affected sources in Oklahoma, which included OG&E. The EPA did not approve or disapprove the applications, however, additional information was requested from the ODEQ by the EPA regarding OG&E's plan. The Company cannot predict what action the EPA or the ODEQ will take in response to OG&E's May 30, 2008 filing or the November 4, 2008 letter from the EPA. Until the compliance plan is approved, the total cost of compliance, including capital expenditures, cannot be estimated by OG&E with a reasonable degree of certainty. Due to this uncertainty regarding BART costs, the Company has excluded any BART costs from its foregoing capital expenditure estimates. OG&E also has approximately 440 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.

#### Refinancing of Long-Term Debt

In late 2009, Enogex intends to refinance its \$400.0 million medium-term notes which mature in January 2010. Due to uncertainty in the current credit markets, at this time, Enogex cannot predict how interest rates will affect its ability to obtain financing on favorable terms.

#### Pension and Postretirement Benefit Plans

All eligible employees of the Company and participating affiliates are covered by a non-contributory defined benefit pension plan. During 2008, actual asset returns for the Company's defined benefit pension plan were negatively affected by the slowdown in growth in the equity markets. At December 31, 2008, approximately 45 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 2008, asset returns on the pension plan decreased approximately 25.1 percent as compared to an increase of approximately 4.4 percent in 2007. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline.

During both 2008 and 2007, the Company made contributions to its pension plan of approximately \$50.0 million. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and increases in discount rates will reduce funding requirements to the plan. During 2009, the Company may contribute up to \$50.0 million to its pension plan.

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 88, "Employer's Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," a one-time settlement charge is required to be recorded by an organization when lump-sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation or the retirement restoration benefit obligation during a plan year exceed the service cost and interest cost components of the organization's net periodic pension cost or retirement restoration cost. During 2007, the Company experienced an increase in both the number of employees electing to retire and the amount of lump-sum payments to be paid to such employees upon retirement as well as the death of the Company's Chairman and Chief Executive Officer in September 2007. As a result, the Company recorded a pension settlement charge and a retirement restoration plan settlement charge in 2007. The Company did not record a pension settlement charge during 2008. 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 <sup>(A)</sup>	Enogex	OG&E Energy	Total
<b>Pension settlement charge:</b>				
2007	\$13.3	\$0.5	\$2.9	\$16.7
<b>Retirement restoration plan settlement charge:</b>				
2007	\$ 0.1	\$ -	\$2.2	\$ 2.3

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

As discussed in Note 13 of Notes to Consolidated Financial Statements, in 2000 the Company made several changes to its pension plan, including the adoption of a cash balance benefit feature for employees hired on or after February 1, 2000. The cash balance plan may provide lower post-employment pension benefits to employees, which could result in less pension expense being recorded. Over the near term, the Company's cash requirements for the plan are not expected to be materially different than the requirements existing prior to the plan changes. However, as the population of employees included in the cash balance plan feature increases, the Company's cash requirements should decrease and will be much less sensitive to changes in discount rates.

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 pension cost to be recognized in the Consolidated Statements of Income in future periods.

At December 31, 2007, the projected benefit obligation and fair value of assets of the Company's pension plan and restoration of retirement income plan was approximately \$522.0 million and \$514.2 million, respectively, for an underfunded status of approximately \$7.8 million. Also, at December 31, 2007, the accumulated postretirement benefit obligation and fair value of assets of the Company's postretirement benefit plans was approximately \$216.8 million and \$78.5 million, respectively, for an underfunded status of approximately \$138.3 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 pension 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. Among other things, it alters the manner in which pension plan assets and liabilities are valued for purposes of calculating required pension contributions, introduces a new funding requirement for single- and multi-employer defined benefit pension plans, provides legal certainty on a prospective basis for cash balance and other hybrid plans and addresses contributions to defined contribution plans, deduction limits for contributions to retirement plans and investment advice provided to plan participants.

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. While the Company generally has until the last day of the first plan year beginning in 2009 to reflect those changes as part of the plan document, plans must nevertheless comply in operation as of each provision's effective date. See Note 13 of Notes to Consolidated Financial Statements for a further discussion of changes made to the Company's plans in order to comply with the Pension Protection Act.

#### 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 Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings will be adequate over the next three years to meet anticipated cash needs. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

#### Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. At December 31, 2008, the Company had approximately \$298.0 million in outstanding borrowings under its revolving credit agreements and no outstanding commercial paper borrowings. At December 31, 2007, the Company had approximately \$295.0 million in outstanding commercial paper borrowings and no outstanding borrowings under its revolving credit agreements. The following table shows the Company's revolving credit agreements and available cash at December 31, 2008.

(In millions)	Aggregate Commitment	Amount Outstanding	Weighted- Average Interest Rate	Maturity
<b>Revolving credit agreements and available cash</b>				
OGE Energy	\$ 596.0	\$298.0	0.75%	12/6/12
OG&E	389.0	–	–	12/6/12
Enogex	250.0	120.0	1.86%	3/31/13
	1,235.0	418.0	1.07%	
Cash	174.4	N/A	N/A	N/A
Total	\$1,409.4	\$418.0	1.07%	

OGE Energy's and OG&E's ability to access the commercial paper market was adversely impacted by the market turmoil that began in September 2008. Accordingly, in order to ensure the availability of funds, OGE Energy and OG&E utilized borrowings under their revolving credit agreements, which generally bear a higher interest rate and a minimum 30-day maturity compared to commercial paper, which has historically been available at lower interest rates and on a daily basis. However, in late 2008, OGE Energy's and OG&E's revolving credit borrowings had a lower interest rate than commercial paper due to disruptions in the credit markets. In December 2008, OG&E repaid the outstanding borrowings under its revolving credit agreement with a portion of the proceeds received from the issuance of long-term debt in December. OG&E intends to utilize commercial paper in the commercial paper market when available. OGE Energy expects to repay the borrowings under its revolving credit agreement and begin utilizing the commercial paper market when available. Also, OG&E has the necessary regulatory approvals to incur up to \$800 million in short-term borrowings at any time for a two-year period beginning January 1, 2009 and ending December 31, 2010. See Note 12 of Notes to the Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

#### Common Stock

See Note 10 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

#### 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 defined benefit retirement and postretirement plans that cover substantially all of the Company's 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 13 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	+/- \$19.5 million
Discount rate	+/- 0.25 percent	+/- \$16.7 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. Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The Company had no material impairments during 2008, 2007 or 2006.

#### **Commitments and Contingencies**

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

Except as otherwise disclosed in this Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Notes 15 and 16 of Notes to Consolidated Financial Statements and Item 3 in the Company's Form 10-K.

#### **Asset Retirement Obligations**

In accordance with FIN No. 47, "Accounting for Conditional Asset Retirement Obligations," an entity was required to recognize a liability for the fair value of an ARO that was conditional on a future event if the liability's fair value could be reasonably estimated. The fair value of a liability for the conditional ARO was recognized when incurred. Uncertainty surrounding the timing and method of settlement of a conditional ARO was factored into the measurement of the liability when sufficient information existed. However, in some cases, there was insufficient information to estimate the fair value of an ARO. In these cases, the liability was initially recognized in the period in which sufficient information was available for an entity to make a reasonable estimate of the liability's fair value. The Company did not recognize any new AROs during 2008; however, the Company has identified 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**

Enogex engages in cash flow hedge transactions to manage commodity risk. Enogex may hedge its forward exposure to manage the impact of changes in commodity prices. Hedges of anticipated transactions are documented as cash flow hedges pursuant to SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and are executed based upon management-established risk management objectives. During 2006, Enogex utilized hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas, NGL hedges and certain transportation hedges. During 2007, Enogex utilized hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas and NGL hedges. During 2008, Enogex utilized hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas and NGL hedges. Maturities of Enogex's commodity hedging positions at December 31, 2008 occur in 2009 through 2011. OERI utilized hedge accounting to manage commodity exposure for certain transportation and natural gas inventory hedges. Maturities of OERI's commodity hedging positions at December 31, 2008 do not extend beyond the first quarter of 2009. 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 2006 and 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. The treasury lock agreements in 2006 and 2007 qualified as cash flow hedges under SFAS No. 133. The objective of these treasury lock agreements was to protect against the variability of future interest payments of long-term debt that was issued by OG&E.

#### **Electric Utility Segment**

##### **Regulatory Assets and Liabilities**

OG&E, as a regulated utility, is subject to the accounting principles prescribed by SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 provides that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be

included in amounts allowable for recovery or refund in future rates. The Company adopted certain provisions of SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R," effective December 31, 2006, which required the Company to separately disclose the items that had not yet been recognized as components of net periodic pension cost including, net loss, prior service cost and net transition obligation at December 31, 2006. For companies not subject to SFAS No. 71, SFAS No. 158 required these charges to be included in Accumulated Other Comprehensive Income. However, for companies subject to SFAS No. 71, 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 SFAS No. 158 regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

#### **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, 2008, 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 \$0.3 million. At December 31, 2008 and 2007, Accrued Unbilled Revenues were approximately \$47.0 million and \$45.7 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. At December 31, 2008, if the provision rate were to increase or decrease by ten 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 \$2.3 million and \$3.4 million at December 31, 2008 and 2007, 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.

The Company 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 sales 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 through its transportation and storage business. The transportation and storage business maintains natural gas inventory to provide operational support for its pipeline deliveries. In an effort to mitigate market price exposures, Enogex enters into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2008, Enogex recorded a write-down to market value related to natural gas storage inventory of approximately \$0.7 million. 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 \$16.2 million and \$37.7 million at December 31, 2008 and 2007, respectively, which included approximately \$20.9 million of OERI inventory at December 31, 2007. Natural gas storage inventory is presented in Fuel Inventories on the Consolidated Balance Sheets and 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 the Company 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 \$0.9 million and \$0.4 million at December 31, 2008 and 2007, respectively.

### **Marketing Segment**

#### **Operating Revenues**

OERI engages in energy marketing, trading and hedging activities related to the purchase and sale of natural gas as well as hedging activity related to natural gas and NGLs on behalf of Enogex. 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 activities are accounted for in accordance with SFAS No. 133 and Emerging issues Task Force ("EITF") Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading Risk Management Activities." In accordance with SFAS No. 133, contracts that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as Price Risk Management 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 in accordance with SFAS No. 133. Contracts resulting in delivery of a commodity that meet the requirements of EITF Issue No. 99-19, "Reporting Revenues Gross as a Principal or Net as an Agent," 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 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 sales 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 pursuant to SFAS No. 133 and are recorded at fair market value in accordance with SFAS No. 157, "Fair Value Measurements." OERI 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, 2008, unrealized mark-to-market gains were approximately \$24.9 million, which included approximately \$0.2 million of unrealized mark-to-market gains that were calculated utilizing models. At December 31, 2008, 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. All natural gas inventory held by OERI is recorded at the lower of cost or market. During 2008 and 2007, OERI recorded a write-down to market value related to natural gas storage inventory of approximately \$6.2 million and \$3.6 million, respectively. The amount of OERI's natural gas inventory was approximately \$15.9 million at December 31, 2008. Natural gas storage inventory is presented in Fuel Inventories on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

## Quantitative and Qualitative Disclosures About Market Risk

### 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 the Company 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 December 31, 2008.

### Accounting Pronouncements

See Notes 1, 2, 3, 4, 6, 9 and 13 of Notes to Consolidated Financial Statements for a discussion of recent accounting pronouncements that are applicable to the Company.

### Electric Competition; Regulation

OG&E and Enogex have been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although retail restructuring efforts in Oklahoma and Arkansas were postponed for the time being, if such efforts were renewed, retail competition and the unbundling of regulated energy service could have a significant financial impact on the Company due to possible impairments of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. Any such restructuring also could have a significant impact on the Company's consolidated financial position, results of operations and cash flows. The Company cannot predict when it will be subject to changes in legislation or regulation, nor can it predict the impact of these changes on the Company's consolidated financial position, results of operations or cash flows. The Company believes that the prices for electricity and the quality and reliability of the Company's service currently place us in a position to compete effectively in the energy market. OG&E is also subject to competition in various degrees from state-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators. OG&E has a franchise to serve in more than 270 towns and cities throughout its service territory.

### Commitments and Contingencies

Except as disclosed otherwise in this Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Notes 15 and 16 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.

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, interest rate swap agreements, treasury lock agreements and commercial paper. The Company engages in price risk management activities for both trading and non-trading purposes.

### Risk Committee and Oversight

Management monitors market risks using a risk committee structure. The 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 will report quarterly to, the Audit Committee of the 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 will report to the Risk Oversight Committee.

The Company also has a Corporate Risk Management Department led by our 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 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.

The Company's price risk management assets and liabilities as of December 31, 2008 were as follows:

(Dollars and volumes in millions)	Commodity	Notional Volume <sup>(A)</sup>	Maturity	Fair Value
<b>Trading</b>				
Price risk management assets				
Physical purchases	Natural Gas	8.4	2009	\$ 2.2
Physical purchases	Natural Gas	0.9	2010	0.2
Total physical purchases				2.4
Physical sales	Natural Gas	17.4	2009	5.1
Short physical options	Natural Gas	26.5	2009	0.9
Short physical options	Natural Gas	1.4	2010	0.1
Short physical options	Natural Gas	1.4	2011	0.1
Short physical options	Natural Gas	1.4	2012	0.1
Short physical options	Natural Gas	0.8	2013	0.1
Total short physical options				1.3
Short financial swaps/futures (fixed)	Natural Gas	0.4	2009	1.5
Long basis positions	Natural Gas	2.5	2009	0.4
Total trading price risk management assets				\$ 10.7
<b>Non-Trading</b>				
Long financial swaps/futures (fixed)	Natural Gas	0.5	2010	\$1.8
Short financial swaps/futures (fixed)	NGL	1.4	2009	23.7
Short financial swaps/futures (fixed)	NGL	1.3	2010	17.2
Total short financial swaps/futures (fixed)				40.9
Long financial options	NGL	1.3	2009	18.1
Long financial options	NGL	1.3	2010	41.0
Long financial options	NGL	1.3	2011	44.9
Total long financial options				104.0
Total non-trading price risk management assets				\$ 146.7
Total price risk management assets				\$ 157.4
Amounts offset in price risk management through master netting agreements				\$(123.5)
Net price risk management assets				\$ 33.9
<b>Trading</b>				
Price risk management liabilities				
Physical purchases	Natural Gas	6.0	2009	\$ 0.7
Physical sales	Natural Gas	5.9	2009	0.6
Long financial swaps/futures (fixed)	Natural Gas	0.8	2009	0.6
Short financial swaps/futures (fixed)	Natural Gas	0.5	2009	0.2
Long basis positions	Natural Gas	1.8	2009	0.4
Short basis positions	Natural Gas	1.0	2009	0.1
Total trading price risk management liabilities				\$ 2.6
<b>Non-Trading</b>				
Long financial swaps/futures (fixed)	Natural Gas	9.1	2009	\$ 32.3
Long financial swaps/futures (fixed)	Natural Gas	10.6	2010	18.4
Long financial swaps/futures (fixed)	Natural Gas	5.2	2011	17.7
Total long financial swaps/futures (fixed)				68.4
Long basis positions	Natural Gas	0.5	2009	0.1
Short basis positions	Natural Gas	1.4	2009	0.1
Short basis positions	Natural Gas	0.3	2010	0.1
Total short basis positions				0.2
Long financial swaps/futures (fixed)	NGL	0.1	2009	0.2
Total non-trading price risk management liabilities				\$ 68.9
Total price risk management liabilities				\$ 71.5
Amounts offset in price risk management through master netting agreements				\$(65.4)
Net price risk management liabilities				\$ 6.1

<sup>(A)</sup> Natural gas in MMBtu; NGLs in barrels.



The valuation of the Company's price risk management assets and liabilities were 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.

### Interest Rate Risk

The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt and commercial paper. 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, 2008, the Company had no outstanding interest rate swap 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)	2009	2010	2011	2012	2013	Thereafter	Total	12/31/08 Fair Value
<b>Fixed-rate debt<sup>(A)</sup></b>								
Principal amount	\$ –	\$400.0	\$ –	\$ –	\$ –	\$1,510.0	\$1,910.0	\$1,857.0
Weighted-average interest rate	–	8.13%	–	–	–	6.52%	6.85%	–
<b>Variable-rate debt<sup>(B)</sup></b>								
Principal amount	–	–	–	–	\$120.0	\$ 135.3	\$ 255.3	\$ 255.3
Weighted-average interest rate	–	–	–	–	2.97%	2.41%	2.67%	–

<sup>(A)</sup> 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.

<sup>(B)</sup> A hypothetical change of 100 basis points in the underlying variable interest rate would change interest expense by approximately \$2.6 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. The VaR limit set by the Risk Oversight Committee for the Company's trading activities, assuming a 95 percent confidence level, currently is \$1.5 million. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company's operating income.

A sensitivity analysis has been prepared to estimate the Company's exposure to market risk created by trading activities. The value of trading positions is a summation of the fair values calculated for each net commodity position based upon quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in quoted market prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows at December 31, 2008.

(In millions)	Trading
Commodity market risk, net	\$0.1

### Non-Trading Activities

The prices of natural gas, NGLs and NGL 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 hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the Company's operating income. Because the commodities covered by these hedges are substantially the same commodities that the Company buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

A sensitivity analysis has been prepared to estimate the Company's exposure to the market risk of the Company's non-trading activities. The Company's daily net commodity position consists of natural gas inventories, commodity purchase and sales contracts, financial and commodity derivative instruments and anticipated natural gas processing spreads and fuel recoveries. Quoted market prices are not available for all of the Company's non-trading positions; therefore, the value of non-trading positions is a summation of the forecasted values calculated for each commodity based upon internally generated forward price curves. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in such prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows at December 31, 2008.

(In millions)	Non-Trading
Commodity market risk, net	\$6.6

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 under the provisions of SFAS No. 133. Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the 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 to (i) commodity contracts for the purchase and sale of natural gas; (ii) commodity contracts for the sale of NGLs produced by its subsidiary, Enogex Products LLC; (iii) electric power contracts by OG&E; and (iv) fuel procurement by OG&E.

### Credit Risk

Credit risk includes the risk that counterparties that owe the Company money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Company may be forced to enter into alternative arrangements. In that event, the Company's financial results could be adversely affected and the Company could incur losses.

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

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

## Consolidated Statements of Income

(In millions, except per share data, year ended December 31)

	2008	2007	2006
<b>Operating revenues</b>			
Electric Utility operating revenues	\$1,959.5	\$1,835.1	\$1,745.7
Natural Gas Pipeline operating revenues	2,111.2	1,962.5	2,259.9
Total operating revenues	4,070.7	3,797.6	4,005.6
Cost of goods sold (exclusive of depreciation and amortization shown below)			
Electric Utility cost of goods sold	1,061.2	977.8	902.5
Natural Gas Pipeline cost of goods sold	1,756.8	1,656.9	2,000.0
Total cost of goods sold	2,818.0	2,634.7	2,902.5
Gross margin on revenues	1,252.7	1,162.9	1,103.1
Other operation and maintenance	492.2	436.8	416.6
Depreciation and amortization	217.5	195.3	181.4
Impairment of assets	0.4	0.5	0.3
Taxes other than income	80.5	75.0	72.1
Operating income	462.1	455.3	432.7
Other income (expense)			
Interest income	6.7	2.1	6.2
Allowance for equity funds used during construction	-	-	4.1
Other income	15.4	17.4	16.3
Other expense	(31.6)	(23.7)	(16.7)
Net other income (expense)	(9.5)	(4.2)	9.9
Interest expense			
Interest on long-term debt	103.0	87.8	87.4
Allowance for borrowed funds used during construction	(4.0)	(4.0)	(4.5)
Interest on short-term debt and other interest charges	21.0	6.4	13.1
Interest expense	120.0	90.2	96.0
Income from continuing operations before taxes	332.6	360.9	346.6
Income tax expense	101.2	116.7	120.5
<b>Income from continuing operations</b>	<b>231.4</b>	<b>244.2</b>	<b>226.1</b>
<b>Discontinued operations</b> (note 7)			
Income from discontinued operations	-	-	59.1
Income tax expense	-	-	23.1
Income from discontinued operations	-	-	36.0
<b>Net income</b>	<b>\$ 231.4</b>	<b>\$ 244.2</b>	<b>\$ 262.1</b>
Basic average common shares outstanding	92.4	91.7	91.0
Diluted average common shares outstanding	92.8	92.5	92.1
Basic earnings per average common share			
Income from continuing operations	\$ 2.50	\$ 2.66	\$ 2.48
Income from discontinued operations, net of tax	-	-	0.40
<b>Net income</b>	<b>\$ 2.50</b>	<b>\$ 2.66</b>	<b>\$ 2.88</b>
Diluted earnings per average common share			
Income from continuing operations	\$ 2.49	\$ 2.64	\$ 2.45
Income from discontinued operations, net of tax	-	-	0.39
<b>Net income</b>	<b>\$ 2.49</b>	<b>\$ 2.64</b>	<b>\$ 2.84</b>
<b>Dividends declared per share</b>	<b>\$ 1.3975</b>	<b>\$ 1.3675</b>	<b>\$ 1.3375</b>

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

## Consolidated Balance Sheets

(In millions, December 31)

	2008	2007
<b>Assets</b>		
Current assets		
Cash and cash equivalents	\$ 174.4	\$ 8.8
Accounts receivable, less reserve of \$3.2 and \$3.8, respectively	288.1	334.4
Accrued unbilled revenues	47.0	45.7
Fuel inventories	88.7	82.0
Materials and supplies, at average cost	72.1	63.6
Price risk management	11.9	7.7
Gas imbalances	6.2	6.7
Accumulated deferred tax assets	14.9	38.1
Fuel clause under recoveries	24.0	27.3
Prepayments	9.0	8.0
Other	8.3	7.2
Total current assets	744.6	629.5
Other property and investments, at cost	42.2	44.5
Property, plant and equipment		
In service	7,722.4	6,809.2
Construction work in progress	399.0	179.8
Total property, plant and equipment	8,121.4	6,989.0
Less accumulated depreciation	2,871.6	2,742.7
Net property, plant and equipment	5,249.8	4,246.3
Deferred charges and other assets		
Income taxes recoverable from customers, net	14.6	17.4
Regulatory asset – SFAS No. 158	344.7	174.6
Price risk management	22.0	0.3
McClain Plant deferred expenses	6.2	12.4
Unamortized loss on reacquired debt	17.7	18.9
Unamortized debt issuance costs	13.5	8.3
Other	63.2	85.6
Total deferred charges and other assets	481.9	317.5
Total assets	<b>\$6,518.5</b>	<b>\$5,237.8</b>

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

(In millions, December 31)

	2008	2007
<b>Liabilities and stockholders' equity</b>		
Current liabilities		
Short-term debt	\$ 298.0	\$ 295.8
Accounts payable	279.7	399.3
Dividends payable	33.2	31.9
Customer deposits	58.8	55.5
Accrued taxes	26.8	40.0
Accrued interest	48.7	37.0
Accrued compensation	45.2	53.9
Long-term debt due within one year	-	1.0
Price risk management	2.3	20.6
Gas imbalances	24.9	11.1
Fuel clause over recoveries	8.6	4.2
Other	62.2	38.2
Total current liabilities	888.4	988.5
Long-term debt	2,161.8	1,344.6
Commitments and contingencies (note 15)		
Deferred credits and other liabilities		
Accrued benefit obligations	350.5	156.2
Accumulated deferred income taxes	996.9	853.6
Accumulated deferred investment tax credits	17.3	22.0
Accrued removal obligations, net	150.9	139.7
Price risk management	3.8	11.3
Other	52.1	41.0
Total deferred credits and other liabilities	1,571.5	1,223.8
Stockholders' equity		
Common stockholders' equity	802.9	756.2
Retained earnings	1,107.6	1,005.7
Accumulated other comprehensive loss, net of tax	(13.7)	(81.0)
Total stockholders' equity	1,896.8	1,680.9
Total liabilities and stockholders' equity	\$6,518.5	\$5,237.8

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

## Consolidated Statements of Capitalization

(In millions, December 31)

	2008	2007
<b>Stockholders' equity</b>		
Common stock, par value \$0.01 per share; authorized 125.0 shares; and outstanding 93.5 and 91.8 shares, respectively	\$ 0.9	\$ 0.9
Premium on capital stock	802.0	755.3
Retained earnings	1,107.6	1,005.7
Accumulated other comprehensive loss, net of tax	(13.7)	(81.0)
<b>Total stockholders' equity</b>	<b>1,896.8</b>	<b>1,680.9</b>
<b>Long-term debt</b>		
Senior Notes – OGE Energy Corp.		
5.00% Senior Notes, Series Due November 15, 2014	100.0	100.0
Unamortized discount	(0.5)	(0.6)
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	–
8.25% Senior Notes, Series Due January 15, 2019	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	–
Other Bonds – OG&E		
1.40% – 8.35% Garfield Industrial Authority, January 1, 2025	47.0	47.0
1.24% – 8.14% Muskogee Industrial Authority, January 1, 2025	32.4	32.4
1.35% – 7.75% Muskogee Industrial Authority, June 1, 2027	55.9	56.0
Unamortized discount	(3.9)	(2.0)
Enogex		
7.07% Medium-Term Notes, Series Due 2008	–	1.0
8.125% Medium-Term Notes, Series Due 2010	400.0	400.0
0.31% – 4.67% Enogex Revolving Credit Facility Due 2013	120.0	–
Unamortized swap monetization	0.9	1.8
<b>Total long-term debt</b>	<b>2,161.8</b>	<b>1,345.6</b>
Less long-term debt due within one year	–	1.0
<b>Total long-term debt (excluding long-term debt due within one year)</b>	<b>2,161.8</b>	<b>1,344.6</b>
<b>Total Capitalization</b>	<b>\$4,058.6</b>	<b>\$3,025.5</b>

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)	Total
<b>Balance at December 31, 2005</b>	\$0.9	\$714.6	\$ 750.5	\$(90.2)	\$1,375.8
Comprehensive income					
Net income for 2006	-	-	262.1	-	262.1
Other comprehensive income, net of tax					
Minimum pension liability adjustment, net of tax (\$147.5 pre-tax)	-	-	-	90.4	90.4
Minimum pension liability adjustment – SFAS No. 158, net of tax (\$1.1 pre-tax)	-	-	-	0.7	0.7
Deferred hedging gains, net of tax (\$4.1 pre-tax)	-	-	-	2.5	2.5
Amortization of cash flow hedge, net of tax (\$0.5 pre-tax)	-	-	-	0.3	0.3
Other comprehensive income	-	-	-	93.9	93.9
Comprehensive income	-	-	262.1	93.9	356.0
Adjustment to initially apply SFAS No. 158, net of tax					
Defined benefit pension plan and restoration of retirement income plan:					
Net loss, net of tax ((\$33.9) pre-tax)	-	-	-	(20.7)	(20.7)
Prior service cost, net of tax ((\$6.6) pre-tax)	-	-	-	(4.1)	(4.1)
Defined benefit postretirement plans:					
Net loss, net of tax ((\$11.7) pre-tax)	-	-	-	(5.4)	(5.4)
Net transition obligation, net of tax ((\$1.2) pre-tax)	-	-	-	(0.8)	(0.8)
Prior service cost, net of tax ((\$1.2) pre-tax)	-	-	-	(0.7)	(0.7)
Adjustment to initially apply SFAS No. 158, net of tax	-	-	-	(31.7)	(31.7)
Dividends declared on common stock	-	-	(121.8)	-	(121.8)
Issuance of common stock	-	25.5	-	-	25.5
<b>Balance at December 31, 2006</b>	0.9	740.1	890.8	(28.0)	1,603.8
Comprehensive income					
Net income for 2007	-	-	244.2	-	244.2
Other comprehensive income, 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	-	-	244.2	(53.0)	191.2
Dividends declared on common stock	-	-	(125.5)	-	(125.5)
FIN No. 48 adoption ((\$6.2) pre-tax)	-	-	(3.8)	-	(3.8)
Issuance of common stock	-	15.2	-	-	15.2
<b>Balance at December 31, 2007</b>	0.9	755.3	1,005.7	(81.0)	1,680.9
Comprehensive income					
Net income for 2008	-	-	231.4	-	231.4
Other comprehensive income, 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	298.7
Dividends declared on common stock	-	-	(129.5)	-	(129.5)
Issuance of common stock	-	46.7	-	-	46.7
<b>Balance at December 31, 2008</b>	\$0.9	\$802.0	\$1,107.6	\$(13.7)	\$1,896.8

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

## Consolidated Statements of Cash Flows

(In millions, year ended December 31)

	2008	2007	2006
<b>Cash flows from operating activities</b>			
Income from continuing operations	\$ 231.4	\$ 244.2	\$ 226.1
Adjustments to reconcile income from continuing operations to net cash provided from operating activities			
Minority interest income	6.1	1.0	–
Depreciation and amortization	217.5	195.3	181.4
Impairment of assets	0.4	0.5	0.3
Deferred income taxes and investment tax credits, net	123.4	16.1	32.3
Allowance for equity funds used during construction	–	–	(4.1)
Loss (gain) on sale of assets	0.1	(0.1)	(1.6)
Loss on retirement and abandonment of fixed assets	0.2	3.8	6.0
Write-down of regulatory assets	9.2	–	–
Stock-based compensation expense	4.3	3.6	3.8
Excess tax benefit on stock-based compensation	(1.9)	(2.8)	(1.4)
Price risk management assets	(25.9)	32.0	58.2
Price risk management liabilities	126.9	(74.3)	(83.5)
Other assets	5.1	(24.8)	(73.7)
Other liabilities	(22.9)	(61.5)	18.1
Change in certain current assets and liabilities			
Funds on deposit	–	32.0	(32.0)
Accounts receivable, net	46.3	9.9	247.1
Accrued unbilled revenues	(1.3)	(6.0)	2.1
Fuel, materials and supplies inventories	(15.2)	(21.3)	(4.4)
Gas imbalance asset	0.5	(3.9)	29.2
Fuel clause under recoveries	3.3	(27.3)	101.1
Other current assets	(2.2)	5.4	9.3
Accounts payable	(119.6)	104.3	(215.4)
Customer deposits	3.3	2.1	5.6
Accrued taxes	(9.0)	(13.5)	(7.2)
Accrued interest	11.7	(7.0)	5.8
Accrued compensation	(8.7)	7.9	5.7
Gas imbalance liabilities	13.8	–	(24.9)
Fuel clause over recoveries	4.4	(92.1)	96.3
Other current liabilities	23.8	5.0	(10.7)
Net cash provided from operating activities	625.0	328.5	569.5
<b>Cash flows from investing activities</b>			
Capital expenditures (less allowance for equity funds used during construction)	(1,184.5)	(557.7)	(486.6)
Proceeds from sale of assets	0.8	1.4	3.2
Capital contribution to unconsolidated affiliate	(0.3)	–	–
Other investing activities	(0.1)	–	(0.1)
Net cash used in investing activities	(1,184.1)	(556.3)	(483.5)
<b>Cash flows from financing activities</b>			
Proceeds from long-term debt	743.0	–	217.5
Proceeds from line of credit	145.0	–	–
Issuance of common stock	36.4	8.2	14.5
Increase (decrease) in short-term debt, net	2.2	295.8	(250.0)
Excess tax benefit on stock-based compensation	1.9	2.8	1.4
Contributions from partners	0.5	9.7	–
Repayment of line of credit	(25.0)	–	–
Retirement of long-term debt	(51.1)	(3.1)	–
Dividends paid on common stock	(128.2)	(124.7)	(120.8)
Net cash provided from (used in) financing activities	724.7	188.7	(137.4)
Discontinued operations			
Net cash used in operating activities	–	–	(19.9)
Net cash provided from investing activities	–	–	92.8
Net cash provided from discontinued operations	–	–	72.9
Net increase (decrease) in cash and cash equivalents	165.6	(39.1)	21.5
Cash and cash equivalents at beginning of period	8.8	47.9	26.4
Cash and cash equivalents at end of period	\$ 174.4	\$ 8.8	\$ 47.9

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 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”) is a provider of integrated natural gas midstream services. The vast majority of Enogex’s natural gas gathering, processing, transportation and storage assets are strategically located primarily in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex’s ongoing operations are organized into two business segments: (1) natural gas transportation and storage and (2) natural gas gathering and processing. Historically, Enogex had also engaged in natural gas marketing through its former subsidiary, OGE Energy Resources, Inc. (“OERI”). 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. Accordingly, the discussion that follows includes the results of OERI, but as of January 1, 2008, Enogex no longer has any interest in the results of OERI. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream, LLC joint venture through Enogex Atoka LLC (“Atoka”), a wholly owned subsidiary of Enogex.

Effective April 1, 2008, Enogex Inc. converted from an Oklahoma corporation to a Delaware limited liability company. Also, effective April 1, 2008, Enogex Products Corporation (“Products”), a wholly owned subsidiary of Enogex, converted from an Oklahoma corporation to an Oklahoma limited liability company.

In July 2008, OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture to construct high-capacity transmission line projects in western Oklahoma. The Company will own 50 percent of the joint venture. The joint venture is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. Work on the joint venture projects is scheduled to begin in late 2009 and is targeted for completion by the end of 2013.

The Company allocates 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.

#### Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to the accounting principles prescribed by the Financial Accounting Standards Board (“FASB”) Statement of Financial Accounting Standards (“SFAS”) No. 71, “Accounting for the Effects of Certain Types of Regulation.” SFAS No. 71 provides that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management’s expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

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

The following table is a summary of OG&E’s regulatory assets and liabilities at December 31:

(In millions, December 31)	2008	2007
<b>Regulatory assets</b>		
Regulatory asset – SFAS No. 158	\$344.7	\$174.6
Deferred storm expenses	32.2	35.9
Fuel clause under recoveries	24.0	27.3
Unamortized loss on reacquired debt	17.7	18.9
Income taxes recoverable from customers, net	14.6	17.4
Deferred pension plan expenses	14.6	24.8
Red Rock deferred expenses	7.4	14.7
McClain Plant deferred expenses	6.2	12.4
Cogeneration credit rider under recovery	1.4	3.9
Miscellaneous	1.5	0.8
Total regulatory assets	<b>\$464.3</b>	<b>\$330.7</b>
<b>Regulatory liabilities</b>		
Accrued removal obligations, net	\$150.9	\$139.7
Fuel clause over recoveries	8.6	4.2
Miscellaneous	4.5	4.3
Total regulatory liabilities	<b>\$164.0</b>	<b>\$148.2</b>

The Company adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R," effective December 31, 2006, which required the Company to separately disclose the items that had not yet been recognized as components of net periodic pension cost including, net loss, prior service cost and net transition obligation at December 31, 2006. For companies not subject to SFAS No. 71, SFAS No. 158 required these charges to be included in Accumulated Other Comprehensive Income. However, for companies subject to SFAS No. 71, 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 SFAS No. 158 regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

The following table is a summary of the components of the SFAS No. 158 regulatory asset at December 31:

(In millions, December 31)	2008	2007
<b>Defined benefit pension plan and restoration of retirement income plan:</b>		
Net loss	\$259.8	\$112.3
Prior service cost	3.5	4.8
<b>Defined benefit postretirement plans:</b>		
Net loss	70.4	42.5
Net transition obligation	10.2	12.7
Prior service cost	0.8	2.3
<b>Total</b>	<b>\$344.7</b>	<b>\$174.6</b>

The following amounts in the SFAS No. 158 regulatory asset at December 31, 2008 are expected to be recognized as components of net periodic benefit cost in 2009:

(In millions)	
<b>Defined benefit pension plan and restoration of retirement income plan:</b>	
Net loss	\$20.4
Prior service cost	1.2
<b>Defined benefit postretirement plans:</b>	
Net loss	3.6
Net transition obligation	2.5
Prior service cost	1.5
<b>Total</b>	<b>\$29.2</b>

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.

For a discussion of regulatory matters related to the deferred storm expenses and deferred Red Rock expenses and related reductions in the amounts previously recorded, see Note 16.

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

In accordance with the OCC order received by OG&E in December 2005 in its Oklahoma rate case, OG&E was allowed to recover a certain amount of pension plan expenses. At December 31, 2008, there was approximately \$14.6 million of expenses exceeding this level primarily related to pension settlement charge recorded by the Company during 2007 (see Note 13 for a further discussion). These excess amounts have been recorded as a regulatory asset as OG&E believes these expenses are probable of future recovery.

Income taxes recoverable from customers represent income tax benefits previously used to reduce OG&E's revenues. These amounts are being recovered in rates as the temporary differences that generated the income tax benefit turn around. The provisions of SFAS No. 71 allowed OG&E to treat these amounts as regulatory assets and liabilities and they are being amortized over the estimated remaining life of the assets to which they relate. 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." The OCC authorized approximately \$30.1 million of the \$32.8 million regulatory asset balance at December 31, 2005 to be included in OG&E's rate base for purposes of earning a return.

As a result of the acquisition of a 77 percent interest in the 520 megawatt ("MW") natural gas-fired combined cycle NRG McClain Station (the "McClain Plant") completed on July 9, 2004, and consistent with the 2002 agreed-upon settlement of an OG&E rate case with the OCC, OG&E had the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition and operation of the McClain Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. At December 31, 2008, the McClain Plant regulatory asset was approximately \$6.2 million which is being recovered over the remaining one-year time period as authorized in the OCC rate order which began in January 2006. Approximately \$15.5 million of the McClain Plant deferred expenses are included in OG&E's rate base for purposes of earning a return.

OG&E's cogeneration credit rider was initially implemented in 2003 as part of the Oklahoma retail customer electric rates in order to return purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration previously included in base rates to OG&E's customers. The cogeneration credit rider has been updated and approved by the OCC in December of each year through December 2007 and any over/under recovery of the cogeneration credit rider in the current year and prior periods was automatically included in the next year's rider. OG&E's current cogeneration credit rider expires on December 31, 2009. The balance of the cogeneration credit rider under recovery was approximately \$1.4 million and \$3.9 million, respectively, at December 31, 2008 and 2007. The cogeneration credit rider under recovery was not included in OG&E's rate base and did not otherwise earn a rate of return. The cogeneration credit rider under recovery is included in Other Current Assets on the Company's Consolidated Balance Sheets.

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 reduced or written off, as appropriate. If the Company were required to discontinue the application of SFAS No. 71 for some or all of its operations, it could result in writing off the related regulatory assets; the financial effects of which could be significant.

#### **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 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. The allowance for uncollectible accounts receivable for Enogex is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when the Company believes the collection of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was approximately \$3.2 million and \$3.8 million at December 31, 2008 and 2007, 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 and the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty. Enogex and OERI also monitor the financial position of existing counterparties on an ongoing basis.

#### **Fuel Inventories**

##### **OG&E**

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. Historically, OG&E has used the last-in, first-out ("LIFO") method of accounting for inventory removed from storage or stockpiles. Effective January 1, 2008, OG&E began using the weighted-average cost method to value inventory that is physically added to or withdrawn from storage or stockpiles in accordance with Oklahoma Senate Bill No. 609 ("SB 609") that was adopted in Oklahoma in 2007. SB 609 requires that electric utilities record fuel or natural gas removed from storage or stockpiles using the weighted-average cost method of accounting for inventory. In addition to satisfying the requirements of SB 609, management believes that the change from LIFO to weighted-average cost is also preferable because it provides for a more meaningful presentation in the financial statements taken as a whole and reduces the volatility associated with fuel price fluctuations on OG&E's customers. The majority of electric utility companies use the weighted-average cost method.

SFAS No. 154, "Accounting Changes and Error Corrections, a replacement of Accounting Principles Board ("APB") Opinion No. 20 and FASB Statement No. 3," requires that an entity report a change in accounting principle through retrospective application of the new principle to all prior periods unless it is impractical to do so. However, SFAS No. 71 requires that changes in accounting methods for regulated entities that affect allowable costs for rate-making purposes should be implemented in the same way that such an accounting change would be implemented for rate-making purposes. In accordance with an order from the OCC, OG&E's change in accounting method for inventory affected allowable costs for rate-making purposes, on a prospective basis only beginning January 1, 2008. Therefore the change in accounting was implemented prospectively for purposes of generally accepted accounting principles ("GAAP") and OG&E did not restate previously issued financial statements. Also, in accordance with the order from the OCC, on January 1, 2008, OG&E recorded an increase in Fuel Inventories of approximately \$7.9 million with a corresponding offset recorded in Fuel Clause Under and Over Recoveries on the Company's Consolidated Financial Statements. OG&E began recovering costs from its customers using the weighted-average cost method for inventory on January 1, 2008.

The change in accounting for fuel inventory to the weighted-average cost method resulted in a higher fuel inventory balance of approximately \$0.4 million at December 31, 2008. The change in accounting for fuel inventory to the weighted-average cost method did not impact the income statement for the year ended December 31, 2008 as OG&E's fuel costs are passed through to its customers through fuel adjustment clauses.

The amount of fuel inventory was approximately \$56.6 million and \$44.3 million at December 31, 2008 and 2007, respectively. The estimated replacement cost of fuel inventories was higher than the stated LIFO cost by approximately \$7.4 million for 2007 based on the average cost of fuel purchased.

### Enogex

Natural gas inventory is held by Enogex through its transportation and storage business. The transportation and storage business maintains natural gas inventory to provide operational support for its pipeline deliveries. In an effort to mitigate market price exposures, Enogex enters into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2008, Enogex recorded a write-down to market value related to natural gas storage inventory of approximately \$0.7 million. 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 \$16.2 million and \$37.7 million at December 31, 2008 and 2007, respectively, which included approximately \$20.9 million of OERI inventory at December 31, 2007. Natural gas storage inventory is presented in Fuel Inventories on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

### OERI

Natural gas inventory is held by 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 2008 and 2007, OERI recorded write-downs to market value related to natural gas storage inventory of approximately \$6.2 million and \$3.6 million, respectively. The amount of OERI's natural gas inventory was approximately \$15.9 million at December 31, 2008. Natural gas storage inventory is presented in Fuel Inventories on the Consolidated Balance Sheets and 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. 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 are 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 less net salvage 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 table presents OG&E's ownership interest in the jointly-owned McClain Plant and the jointly-owned 1,230 MW natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma (the "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 this table. 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
<b>2008</b>				
McClain Plant	77	\$181.0	\$44.6	\$136.4
Redbud Facility	51	496.6 <sup>(A)</sup>	63.9 <sup>(B)</sup>	432.7

(In millions, December 31)	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
<b>2007</b>				
McClain Plant	77	\$181.0	\$35.4	\$145.6

<sup>(A)</sup> This amount includes a plant acquisition adjustment of approximately \$153.7 million.

<sup>(B)</sup> This amount includes accumulated amortization of the plant acquisition adjustment of approximately \$1.5 million.

### Enogex

All property, plant and equipment are 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.

Enogex owns a 50 percent membership interest in the Atoka joint venture and acts as the managing member and operator of the facilities owned by the joint venture. The Atoka joint venture constructed, owns and/or operates a gathering system and processing plant and related facilities relating to production in certain areas in southeastern Oklahoma. The gathering system and processing plant were placed in service during the third quarter of 2007. The below table presents 100 percent of the Atoka property, plant and equipment and accumulated depreciation balances as it is accounted for as a minority interest in the Company's consolidated financial statements.

(In millions, December 31)	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
<b>2008</b>				
Atoka processing plant	50	\$32.4	\$1.5	\$30.9
<b>2007</b>				
Atoka processing plant	50	\$18.3	\$0.3	\$18.0

### OERI

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

### OGE Energy Consolidated

The Company's property, plant and equipment and related accumulated depreciation are divided into the following major classes at December 31, 2008 and 2007, respectively.

(In millions, December 31)	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
<b>2008</b>			
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
<b>2007</b>			
OGE Energy (holding company)			
Property, plant and equipment	\$ 93.0	\$ 65.4	\$ 27.6
OGE Energy property, plant and equipment	93.0	65.4	27.6
OG&E			
Distribution assets	2,361.4	792.0	1,569.4
Electric generation assets	2,114.0	1,062.8	1,051.2
Transmission assets	747.3	285.7	461.6
Intangible plant	35.8	29.7	6.1
Other property and equipment	217.0	71.7	145.3
OG&E property, plant and equipment	5,475.5	2,241.9	3,233.6
Enogex			
Transportation and storage assets	729.2	191.4	537.8
Gathering and processing assets	684.0	237.2	446.8
OERI property, plant and equipment	7.3	6.8	0.5
Enogex property, plant and equipment	1,420.5	435.4	985.1
Total property, plant and equipment	\$6,989.0	\$2,742.7	\$4,246.3

## Depreciation and Amortization

### OG&E

The provision for depreciation, which was approximately 2.7 percent of the average depreciable utility plant for both 2008 and 2007, 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 2009, the provision for depreciation is projected to be approximately 2.8 percent of the average depreciable utility plant. Amortization of intangibles is computed using the straight-line method. Approximately 6.3 percent of the remaining amortizable intangible plant balance at December 31, 2008 will be amortized over three years with approximately 37 percent of the remaining amortizable intangible plant balance at December 31, 2008 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 on the acquired asset. Plant acquisition adjustments include approximately \$153.7 million for the Redbud Facility, which will be amortized over a 27-year life and approximately \$0.5 million for certain substation facilities in OG&E's service territory, which will be 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.

### OERI

Depreciation is computed principally on the straight-line method using estimated useful lives of three to 20 years. 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 accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations," for periods subsequent to the initial measurement of an ARO, the Company recognizes period-to-period changes in the liability for an ARO resulting from: (i) the passage of time; and (ii) revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Also, in accordance with FASB Interpretation ("FIN") No. 47, "Accounting for Conditional Asset Retirement Obligations," the Company recognizes a liability for the fair value of an ARO that is conditional on a future event if the liability's fair value can be reasonably estimated. The fair value of a liability for the conditional ARO is recognized when incurred. Uncertainty surrounding the timing and method of settlement of a conditional ARO is factored into the measurement of the liability

when sufficient information existed. However, in some cases, there is insufficient information to estimate the fair value of an ARO. In these cases, the liability is initially recognized in the period in which sufficient information is available for the Company to make a reasonable estimate of the liability's fair value. The Company did not recognize any new AROs during 2008; however, the Company has identified 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. Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The Company had no material impairments during 2008, 2007 or 2006.

## 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 3.58 percent, 5.78 percent and 7.79 percent for the years 2008, 2007 and 2006, respectively. The decrease in the AFUDC rates in 2008 was primarily due to lower interest rates on short-term borrowings.

## 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. An amount is accrued as a receivable for this unbilled revenue 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.* In February 2007, OG&E began participating in the Southwest Power Pool's ("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 ("NGL") 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.

Estimates for gas purchases are based on sales 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.

The Company 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.

### OERI

OERI engages in energy marketing, trading and hedging activities related to the purchase and sale of natural gas as well as hedging activity related to natural gas and NGLs on behalf of Enogex. 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 activities are accounted for in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and Emerging Issues Task Force ("EITF") Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." In accordance with SFAS No. 133, contracts that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as Price Risk Management Assets or Price Risk Management 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 in accordance with SFAS No. 133. Contracts resulting in delivery of a commodity that meet the requirements of EITF Issue No. 99-19, "Reporting Revenues Gross as a Principal or Net as an Agent," 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, 2008 and 2007 are as follows:

(In millions, December 31)	2008	2007
<b>Defined benefit pension plan and restoration of retirement income plan:</b>		
Net loss, net of tax ((\$71.6) and (\$29.4) pre-tax, respectively)	<b>\$(43.8)</b>	\$(18.0)
Prior service cost, net of tax ((\$0.8) and (\$1.1) pre-tax, respectively)	<b>(0.5)</b>	(0.8)
<b>Defined benefit postretirement plans:</b>		
Net loss, net of tax ((\$8.6) and (\$6.0) pre-tax, respectively)	<b>(5.3)</b>	(3.7)
Net transition obligation, net of tax ((\$0.8) and (\$1.0) pre-tax, respectively)	<b>(0.5)</b>	(0.7)
Prior service cost, net of tax ((\$0.3) and (\$0.7) pre-tax, respectively)	<b>(0.2)</b>	(0.4)
Deferred hedging gains (losses), net of tax (\$62.4 and (\$90.9) pre-tax, respectively)	<b>38.1</b>	(55.7)
Settlement and amortization of cash flow hedge, net of tax ((\$2.4) and (\$2.7) pre-tax, respectively)	<b>(1.5)</b>	(1.7)
Total accumulated other comprehensive loss, net of tax	<b>\$(13.7)</b>	\$(81.0)

Approximately \$12.8 million of the deferred hedging losses at December 31, 2008 are expected to be recognized into earnings during 2009.

### 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, 2008 that are expected to be recognized as components of net periodic benefit cost in 2009 which are as follows:

(In millions)	
<b>Defined benefit pension plan and restoration of retirement income plan:</b>	
Net loss, net of tax (\$5.5 pre-tax)	\$3.4
Prior service cost, net of tax (\$0.3 pre-tax)	0.2
<b>Defined benefit postretirement plans:</b>	
Net loss, net of tax (\$0.8 pre-tax)	0.5
Prior service cost, net of tax (\$0.4 pre-tax)	0.2
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.

### 2. Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 141 (Revised), "Business Combinations," which is intended to improve the relevance, representational faithfulness and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. SFAS No. 141(R) replaces SFAS No. 141, "Business Combinations," and establishes principles and requirements for how the acquirer: (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) applies to all transactions or other events in which an entity obtains control of one or more businesses and combinations achieved without the transfer of consideration. SFAS No. 141(R) also applies to all business entities, including mutual entities that previously used the pooling-of-interests method of accounting for some business combinations. SFAS No. 141(R) does not apply to: (i) the formation of a joint venture; (ii) the acquisition of an asset or a group of assets that does not constitute a business; (iii) a combination between entities or businesses under common control; or (iv) a combination between not-for-profit organizations or the acquisition of a for-profit business by a not-for-profit organization. SFAS No. 141(R) also amends SFAS No. 109, "Accounting for Income Taxes," to require the acquirer to recognize changes in the amount of its deferred tax benefits that are recognizable because of a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. SFAS No. 141(R) is effective for fiscal years, and interim periods within those fiscal years,



beginning on or after December 15, 2008. The provisions of SFAS No. 141(R) are to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The Company adopted this new standard effective January 1, 2009. In anticipation of the adoption of this new standard, the Company wrote off approximately \$4.3 million in 2008 related to transaction costs incurred related to the proposed joint venture between OGE Energy and ETP that has subsequently been terminated.

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

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities," which requires enhanced disclosures about an entity's derivative and hedging activities and is intended to improve the transparency of financial reporting. SFAS No. 161 applies to all entities. SFAS No. 161 applies to all derivative instruments, including bifurcated derivative instruments and related hedging items accounted for under SFAS No. 133. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133 with the intent to provide users of financial statements with an enhanced understanding of: (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008. The Company adopted this new standard effective January 1, 2009. The adoption of this new standard will change the disclosure related to derivative and hedging activities in the Company's consolidated financial statements.

### 3. Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which defines fair value, establishes a framework for measuring fair value in GAAP and establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. SFAS No. 157 expands disclosures about the use of fair value to measure assets and liabilities in interim and annual periods subsequent to initial recognition. The guidance in SFAS No. 157 applies to derivatives and other financial instruments measured at fair value under SFAS No. 133 at initial recognition and in all subsequent periods. Therefore, SFAS No. 157 nullifies the guidance in footnote 3 of EITF Issue No. 02-3. SFAS No. 157 also amends SFAS No. 133 to remove the guidance similar to that nullified in EITF Issue No. 02-3. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The provisions of SFAS No. 157 generally are to be applied prospectively as of the beginning of the fiscal year in which it is initially applied. The Company adopted this new standard effective January 1, 2008.

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

(In millions, December 31)	2008	Level 1	Level 2	Level 3
<b>Assets</b>				
Gross derivative assets	\$243.7	\$83.9	\$38.6	\$121.2
Gas imbalance assets	6.2	–	6.2	–
<b>Total</b>	<b>\$249.9</b>	<b>\$83.9</b>	<b>\$44.8</b>	<b>\$121.2</b>
<b>Liabilities</b>				
Gross derivative liabilities	\$141.8	\$67.7	\$74.1	\$ –
Gas imbalance liabilities <sup>(A)</sup>	13.1	–	13.1	–
Asset retirement obligations	5.2	–	–	5.2
<b>Total</b>	<b>\$160.1</b>	<b>\$67.7</b>	<b>\$87.2</b>	<b>\$ 5.2</b>

<sup>(A)</sup> Gas imbalance liabilities excludes fuel reserves for over/under retained fuel due to/from 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.

The three levels defined by the SFAS No. 157 hierarchy and examples of each are as follows:

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

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

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

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

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

The following table is a reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2008.

(In millions, December 31)	2008
<b>Assets</b>	
Gross derivative assets	\$243.7
Less: amounts held in clearing broker accounts reflected in other current assets	86.3
Less: amounts offset under master netting agreements in accordance with FIN No. 39-1	65.4
Less: collateral payments received from counterparties netted in accordance with FIN No. 39-1	58.1
<b>Net price risk management assets</b>	<b>\$ 33.9</b>
<b>Liabilities</b>	
Gross derivative liabilities	\$141.8
Less: amounts held in clearing broker accounts reflected in other current assets	70.3
Less: amounts offset under master netting agreements in accordance with FIN No. 39-1	65.4
Less: collateral payments to counterparties netted in accordance with FIN No. 39-1	-
<b>Net price risk management liabilities</b>	<b>\$ 6.1</b>

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

(In millions, year ended December 31)	2008
<b>Derivative assets</b>	
Beginning balance	\$ 1.4
Total gains or losses (realized/unrealized)	-
Included in earnings	-
Included in other comprehensive income	2.4
Purchases, sales, issuances and settlements, net <sup>(A)</sup>	82.0
Transfers in and/or out of Level 3 <sup>(B)</sup>	35.4
<b>Ending balance</b>	<b>\$121.2</b>
The amount of total gains or losses for the periods included in earnings attributable to the change in unrealized gains or losses relating to assets held at December 31, 2008	\$ -
<b>Asset retirement obligations</b>	
Beginning balance	\$ 4.9
Total gains or losses (realized/unrealized)	-
Included in earnings	0.3
Included in other comprehensive income	-
Purchases, sales, issuances and settlements, net	-
Transfers in and/or out of Level 3	-
<b>Ending balance</b>	<b>\$ 5.2</b>
The amount of total gains or losses for the periods included in earnings attributable to the change in unrealized gains or losses relating to assets held at December 31, 2008	\$ -

<sup>(A)</sup> Enogex purchased NGL 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.

<sup>(B)</sup> The transfers into Level 3 are primarily due to NGL swaps and shorter-term NGL options being re-categorized 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 year ended December 31, 2008 attributable to the change in unrealized gains or losses relating to assets and liabilities held at December 31, 2008, if any, are reported in operating revenues.

The following information is provided regarding the estimated fair value of the Company's financial instruments, including derivative contracts related to the Company's price risk management activities, as of December 31:

(In millions, December 31)	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Price risk management assets				
Energy trading contracts	\$ 33.9	\$ 33.9	\$ 8.0	\$ 8.0
Price risk management liabilities				
Energy trading contracts	\$ 6.1	\$ 6.1	\$ 30.2	\$ 30.2
Interest rate swap	-	-	1.7	1.7
Long-term debt				
Senior notes	\$1,505.6	\$1,420.8	\$807.4	\$825.3
Industrial authority bonds	135.3	135.3	135.4	135.4
Enogex notes	399.1	436.1	402.8	436.8
Enogex revolving credit facility	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 interest rate swap and energy trading 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 shareholders 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.

Effective January 1, 2006, the Company adopted SFAS No. 123 (Revised), "Share-Based Payment," using the modified prospective transition method. Under that transition method, the Company's compensation cost recognized in the first quarter of 2006 included: (i) compensation cost for all share-based payments granted prior to, but not yet vested as of, January 1, 2006, based on the fair value calculated in accordance with the provisions of SFAS No. 123(R); and (ii) compensation cost for all share-based payments granted in the first quarter of 2006 based on the fair value calculated in accordance with

the provisions of SFAS No. 123(R). Results for prior periods were not restated. As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded compensation expense of approximately \$8.6 million pre-tax (\$5.3 million after tax, or \$0.06 per basic and diluted share) in 2006 related to the Company's share-based payments.

The Company recorded compensation expense of approximately \$4.3 million pre-tax (\$2.7 million after tax, or \$0.03 per basic and diluted share) and approximately \$3.8 million pre-tax (\$2.3 million after tax, or \$0.03 per basic and diluted share) in 2008 and 2007, respectively, related to the Company's share-based payments. Also, during 2008, the Company converted 166,504 performance units based on a payout ratio of 147.33 percent of the target number of performance units granted in February 2005. One-third of the performance units were settled in cash for approximately \$3.0 million and two-thirds of the performance units were settled in the Company's common stock.

The Company issues new shares to satisfy stock option exercises and payouts of earned performance units. During 2008, 2007 and 2006, there were 875,434 shares, 496,565 shares and 738,426 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 \$15.0 million, \$8.2 million and \$14.5 million in 2008, 2007 and 2006, 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 three-year award cycle 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 three-year 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 a three-year award cycle (i.e. three-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 a three-year award cycle (i.e. three-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 under SFAS No. 123(R). If there is no or only a partial payout for the performance units at the end of the three-year award cycle, the unearned performance units are cancelled. During 2008, 2007 and 2006, the Company awarded 242,503, 162,730 and 239,856 performance units, respectively, to certain employees of the Company and its subsidiaries.

### Performance Units – Total Shareholder Return

The Company recorded compensation expense of approximately \$3.2 million pre-tax (\$2.0 million after tax), \$2.3 million pre-tax (\$1.4 million after tax) and \$6.5 million pre-tax (\$4.0 million after tax) in 2008, 2007 and 2006, 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 three-year award cycle 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 three-year 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.

	2008	2007	2006
Expected dividend yield	3.8%	3.6%	4.9%
Expected price volatility	18.7%	15.9%	16.8%
Risk-free interest rate	2.21%	4.47%	4.66%
Expected life of units (in years)	2.84	2.95	2.85
Fair value of units granted	\$33.62	\$24.18	\$22.93

A summary of the activity for the Company's performance units based on TSR at December 31, 2008 and changes during 2008 are summarized in the following table. Following the end of a three-year 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 <sup>(A)</sup>	Aggregate Intrinsic Value
Units outstanding at 12/31/07	363,148	1:1	
Granted <sup>(B)</sup>	181,892	1:1	
Converted	(124,886)	1:1	\$3.8
Forfeited	(43,538)	1:1	
Units outstanding at 12/31/08	376,616	1:1	\$4.9
Units fully vested at 12/31/08 <sup>(C)</sup>	128,755	1:1	\$3.8

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

<sup>(B)</sup> 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.

<sup>(C)</sup> These performance units, which were awarded in 2006 and became fully vested at December 31, 2008, were certified by the Compensation Committee of the Company's Board of Directors in February 2009.

A summary of the activity for the Company's non-vested performance units based on TSR at December 31, 2008 and changes during 2008 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units non-vested at 12/31/07	238,262	\$23.42
Granted <sup>(D)</sup>	181,892	\$33.62
Vested <sup>(E)</sup>	(128,755)	\$22.93
Forfeited	(43,538)	\$27.20
Units non-vested at 12/31/08 <sup>(F)</sup>	247,861	\$30.50

<sup>(D)</sup> 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.

<sup>(E)</sup> These performance units, which were awarded in 2006 and became fully vested at December 31, 2008, were certified by the Compensation Committee of the Company's Board of Directors in February 2009.

<sup>(F)</sup> Of the 247,861 performance units not vested at December 31, 2008, 228,862 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2008, there was approximately \$4.0 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 1.83 years.

### Performance Units – Earnings Per Share

The Company recorded compensation expense of approximately \$1.2 million pre-tax (\$0.7 million after tax), \$1.5 million pre-tax (\$0.9 million after tax) and \$2.0 million pre-tax (\$1.2 million after tax) in 2008, 2007 and 2006, 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 2006, 2007 and 2008 performance units was \$28.00, \$33.59 and \$29.22, respectively.

A summary of the activity for the Company's performance units based on EPS at December 31, 2008 and changes during 2008 are summarized in the following table. Following the end of a three-year performance period, 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 three-year 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 <sup>(A)</sup>	Aggregate Intrinsic Value
Units outstanding at 12/31/07	120,982	1:1	
Granted <sup>(B)</sup>	60,611	1:1	
Converted	(41,618)	1:1	\$2.3
Forfeited	(14,511)	1:1	
Units outstanding at 12/31/08	125,464	1:1	\$2.2
Units fully vested at 12/31/08 <sup>(C)</sup>	42,914	1:1	\$2.2

<sup>(A)</sup> One performance unit = one share of the Company's common stock

<sup>(B)</sup> 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.

<sup>(C)</sup> These performance units, which were awarded in 2006 and became fully vested at December 31, 2008, were certified by the Compensation Committee of the Company's Board of Directors in February 2009.

A summary of the activity for the Company's non-vested performance units based on EPS at December 31, 2008 and changes during 2008 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units non-vested at 12/31/07	79,364	\$30.21
Granted <sup>(D)</sup>	60,611	\$29.22
Vested <sup>(E)</sup>	(42,914)	\$28.00
Forfeited	(14,511)	\$30.01
Units non-vested at 12/31/08 <sup>(F)</sup>	82,550	\$30.66

<sup>(D)</sup> 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.

<sup>(E)</sup> These performance units, which were awarded in 2006 and became fully vested at December 31, 2008, were certified by the Compensation Committee of the Company's Board of Directors in February 2009.

<sup>(F)</sup> Of the 82,550 performance units not vested at December 31, 2008, 76,274 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2008, there was approximately \$1.0 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 2.0 years.

### Stock Options

The Company recorded no compensation expense in 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. The Company recorded compensation expense of approximately \$0.1 million pre-tax (less than \$0.1 million after tax) in 2006 related to stock options.

A summary of the activity for the Company's options at December 31, 2008 and changes during 2008 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 12/31/07	1,138,917	\$21.34		
Exercised	(713,670)	\$20.96	\$8.5	
Options outstanding at 12/31/08	425,247	\$21.98	\$1.6	4.04 years
Options fully vested and exercisable at 12/31/08	425,247	\$21.98	\$1.6	4.04 years

### Restricted Stock

Under the Plans and in the third quarter of 2008, 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. During 2008, the Company awarded 56,798 shares of restricted stock.

The Company recorded compensation expense of approximately \$0.3 million pre-tax (\$0.2 million after tax) in 2008 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 2008 restricted stock was \$30.84.

At December 31, 2008, there was approximately \$1.5 million in unrecognized compensation cost related to non-vested restricted stock which is expected to be recognized over a weighted-average period of 2.74 years.

### 5. Loss on Retirement and Asset Retirement Obligation of Fixed Assets

OG&E had a power supply contract with a large industrial customer that expired on June 1, 2006. OG&E evaluated options to utilize the assets dedicated to that customer and decided to retire these assets as of June 30, 2006. The carrying amount of these assets at June 30, 2006 was approximately \$6.8 million, which was recorded as a pre-tax loss during the second quarter of 2006. This loss was included in Other Expense in the Consolidated Statement of Income. Also, as part of the settlement of the ARO for these assets, OG&E recorded a reduction to the previously recorded ARO for these assets of approximately \$0.9 million in 2006 due to an agreement with a third party to provide removal and remediation services. This reduction is included in Other Expense in the Consolidated Statement of Income.

## 6. Price Risk Management Assets and Liabilities

### Non-Trading Activities

The Company periodically utilizes derivative contracts to manage the exposure of its assets to unfavorable changes in commodity prices, as well as to reduce exposure to adverse interest rate fluctuations. During 2008 and 2007, the Company's use of non-trading price risk management instruments involved the use of commodity price futures, commodity price swap contracts, commodity price option features and treasury lock agreements. The commodity price futures and commodity price swap contracts involved 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 involved 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. The treasury lock agreements help protect against the variability of future interest payments of long-term debt that was issued by OG&E.

In accordance with SFAS No. 133, the Company recognizes its non-exchange traded derivative instruments as Price Risk Management assets or liabilities in the 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. 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 is recognized currently in earnings. 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.

The Company measures the ineffectiveness of commodity cash flow hedges using the change in fair value method prescribed by SFAS No. 133. Under the change in fair value method, the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. The Company recorded less than \$0.1 million for hedge effectiveness of commodity cash flow hedges in 2008. The ineffectiveness of treasury lock cash flow hedges is measured using the hypothetical derivative method prescribed by SFAS No. 133. Under the hypothetical derivative method, the Company designates that the critical terms of the hedging instrument are the same as the critical terms of the hypothetical derivative used to value the forecasted transaction, and, as a result, no ineffectiveness is expected.

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 under the provisions of SFAS No. 133. Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the 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 to: (i) commodity contracts for the purchase and sale of natural gas; (ii) commodity contracts for the sale of NGLs produced by its subsidiary, Products; (iii) electric power contracts by OG&E; and (iv) fuel procurement by OG&E.

During 2008, Enogex utilized non-trading price risk management instruments to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas and NGL hedges. Enogex's commodity hedging activity as of December 31, 2008 covers a three-year period from 2009 through 2011. OERI utilized non-trading price risk management instrument to manage commodity exposure for certain transportation and natural gas inventory hedges. OERI's commodity hedging activity as of December 31, 2008 does not extend beyond the first quarter of 2009.

At December 31, 2007, OG&E's treasury lock agreements were not designated as cash flow hedges under SFAS No. 133. The 2007 treasury lock agreements were settled on January 29, 2008.

### Trading Activities

The Company, through OERI, engages in energy trading activities primarily related to the purchase and sale of natural gas. Contracts utilized in these activities generally include forward swap contracts as well as over-the-counter and exchange traded futures and options. Energy trading activities are accounted for in accordance with SFAS No. 133 and EITF Issue No. 02-3. In accordance with SFAS No. 133, instruments that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as Price Risk Management Assets or Price Risk Management 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 Natural Gas Pipeline Operating Revenues in the Consolidated Statements of Income or in Other Comprehensive Income for derivatives designated and qualifying as cash flow hedges in accordance with SFAS No. 133. Energy trading contracts resulting in delivery of a commodity that meet the requirements of EITF Issue No. 99-19, "Reporting Revenues Gross as a Principal or Net as an Agent," are included as sales or purchases in the Consolidated Statements of Income depending on whether the contract relates to the sale or purchase of the commodity.

In accordance with FIN No. 39 (As Amended), "Offsetting of Amounts Related to Certain Contracts – an interpretation of APB Opinion No. 10 and FASB Statement No. 105," fair value amounts recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset

or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Consolidated Balance Sheets. The Company has presented the fair values of its contracts under master netting agreements using a net fair value presentation. If these transactions with the same counterparty were presented on a gross basis in the Consolidated Balance Sheets, current Price Risk Management assets and liabilities would be approximately \$51.8 million and \$35.4 million, respectively, at December 31, 2008, and non-current Price Risk Management assets and liabilities would be approximately \$105.6 million and \$36.2 million, respectively, at December 31, 2008. If these transactions with the same counterparty were presented on a gross basis in the Consolidated Balance Sheets, current Price Risk Management assets and liabilities would be approximately \$10.0 million and \$51.4 million, respectively, at December 31, 2007, and non-current Price Risk Management assets and liabilities would be approximately \$2.6 million and \$38.9 million, respectively, at December 31, 2007.

### 7. Enogex – Discontinued Operations

In May 2006, Enogex's wholly owned subsidiary, Enogex Gas Gathering LLC, sold certain gas gathering assets in the Kinta, Oklahoma area, which included approximately 568 miles of gathering pipeline and 22 compressor units, for approximately \$92.9 million. Enogex recorded an after tax gain of approximately \$34.1 million from this sale in the second quarter of 2006.

The Consolidated Financial Statements of the Company have been reclassified to reflect the above sale as a discontinued operation. Accordingly, revenues, costs and expenses and cash flows from this sale have been excluded from the respective captions in the Consolidated Financial Statements and have been separately reported as discontinued operations in the applicable financial statement captions. As the above sale occurred prior to 2007, there are no results of operations for discontinued operations during 2007 or 2008. Summarized financial information for the discontinued operations as of December 31 is as follows:

(In millions, year ended December 31)	2008	2007	2006
<b>Consolidated statements of income data</b>			
Operating revenues from discontinued operations	\$ –	\$ –	\$ 9.4
Income from discontinued operations before taxes	–	–	59.1

### 8. 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)	2008	2007	2006
<b>Non-cash investing and financing activities</b>			
Power plant long-term service agreement	\$ 3.5	\$ 0.7	\$ –
Capital lease for distribution equipment	0.3	–	–
<b>Supplemental cash flow information</b>			
Cash paid during the period for			
Interest (net of interest capitalized of \$7.6, \$4.9, \$5.4)	\$122.3	\$93.5	\$ 85.5
Income taxes (net of income tax refunds)	–	86.6	122.7

### 9. Income Taxes

The items comprising income tax expense are as follows:

(In millions, year ended December 31)	2008	2007	2006
<b>Provision (benefit) for current income taxes from continuing operations</b>			
Federal	\$ (18.6)	\$ 96.0	\$ 96.0
State	(0.8)	3.9	(7.4)
Total provision (benefit) for current income taxes from continuing operations	(19.4)	99.9	88.6
<b>Provision for deferred income taxes, net from continuing operations</b>			
Federal	126.9	18.2	35.4
State	1.2	2.7	1.9
Total provision for deferred income taxes, net from continuing operations	128.1	20.9	37.3
Deferred federal investment tax credits, net	(4.6)	(4.8)	(5.0)
Income taxes relating to other income and deductions	(2.9)	0.7	(0.4)
Total income tax expense from continuing operations	\$101.2	\$116.7	\$120.5

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal or state and local income tax examinations by tax authorities for years before 2005. In September 2008, the Internal Revenue Service ("IRS") completed its audit of tax years 2005 and 2006. 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. In addition, OG&E earns both Federal and Oklahoma state tax credits associated with the production from its 120 MW wind farm

in northwestern Oklahoma ("Centennial") that 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)	2008	2007	2006
Statutory Federal tax rate	<b>35.0%</b>	35.0%	35.0%
Amortization of net unfunded deferred taxes	<b>0.7</b>	0.8	0.7
State income taxes, net of Federal income tax benefit	<b>0.2</b>	1.9	2.8
Medicare Part D subsidy	<b>(0.3)</b>	(0.3)	(0.7)
401(k) dividends	<b>(0.8)</b>	(1.2)	(0.9)
Federal investment tax credits, net	<b>(1.4)</b>	(1.3)	(1.4)
Federal renewable energy credit <sup>(A)</sup>	<b>(2.7)</b>	(2.0)	-
Other	<b>(0.3)</b>	(0.6)	(0.7)
Effective income tax rate as reported	<b>30.4%</b>	32.3%	34.8%

<sup>(A)</sup> These are credits OG&E began earning associated with the production from the Centennial wind farm that was placed in service during January 2007.

The Company adopted the provisions of FIN No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109," on January 1, 2007. As a result of the implementation of FIN No. 48, the Company recognized an approximate \$6.2 million increase in the accrued interest liability. The after-tax effect, of approximately \$3.8 million, was accounted for as a reduction to the January 1, 2007 balance of retained earnings. The balance of uncertain tax positions at January 1, 2007 consisted of approximately \$171.6 million of tax positions associated with the capitalization of costs for self-constructed assets. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. OG&E reached a final settlement with the IRS on November 27, 2007 related to the tax method of accounting for the capitalization of costs for self-constructed assets as discussed below. A reconciliation of the beginning and ending amounts of unrecognized tax benefits is as follows:

(In millions, December 31)	2008	2007
Beginning balance	\$ -	\$ 66.4
Settlements with tax authorities	-	\$(66.4)
Ending balance	\$ -	\$ -

The Company recognizes accrued interest related to tax benefits in interest expense and recognizes penalties in other expense. OG&E recorded interest expense associated with the IRS audit of approximately \$0.3 million in 2006 and \$2.6 million in 2007. On November 27, 2007, OG&E reached a final settlement with the IRS related to the tax method of accounting, which resulted in the reversal of approximately \$9.5 million of previously accrued interest expense related to this previously uncertain tax position. At December 31, 2007, the Company had approximately \$2.9 million of accrued interest related to the capitalization of costs for self-constructed assets discussed above.

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

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, 2008 and 2007, respectively, were as follows:

(In millions, December 31)	2008	2007
<b>Current accumulated deferred tax assets</b>		
Federal renewable energy credit	\$ 9.2	\$ -
Accrued vacation	7.2	6.4
Accrued liabilities	5.6	6.3
Uncollectible accounts	1.5	1.6
Derivative instruments	-	19.3
Other	-	4.5
Total current accumulated deferred tax assets	<b>23.5</b>	38.1
<b>Current accumulated deferred tax liabilities</b>		
derivative instruments	(7.0)	-
Other	(1.6)	-
Total current accumulated deferred tax liabilities	<b>(8.6)</b>	-
Current accumulated deferred tax assets, net	\$ 14.9	\$ 38.1
<b>Non-current accumulated deferred tax liabilities</b>		
Accelerated depreciation and other property related differences	\$1,025.7	\$ 889.0
Company pension plan	52.1	60.6
Derivative instruments	17.0	-
Income taxes refundable to customers, net	5.7	6.7
Bond redemption-unamortized costs	5.7	6.1
Regulatory asset	3.2	7.7
Total non-current accumulated deferred tax liabilities	<b>1,109.4</b>	970.1
<b>Non-current accumulated deferred tax assets</b>		
Regulatory liabilities	(58.5)	(54.7)
Postretirement medical and life insurance benefits	(34.3)	(34.3)
State tax credit carryforward	(11.8)	-
Deferred Federal investment tax credits	(6.7)	(8.5)
Derivative instruments	-	(18.9)
Other	(1.2)	(0.1)
Total non-current accumulated deferred tax assets	<b>(112.5)</b>	(116.5)
Non-Current accumulated deferred income tax liabilities, net	\$ 996.9	\$ 853.6

The Company currently estimates a Federal tax operating loss for 2008 of approximately \$32.0 million primarily caused by the accelerated tax depreciation provisions contained within the Economic Stimulus Act of 2008 ("Stimulus Act"). The Stimulus Act allows a current deduction for 50 percent of the cost of certain property placed into service during 2008. This loss results in an approximately \$11.2 current income tax receivable related to the 2008 tax year. It is the Company's intent to carry this tax loss back to a prior period in order to obtain cash refunds. As noted above, the impact of deferred tax accounting will not cause this refund to impact the effective tax rate.



The Company has an Oklahoma investment tax credit carryover from 2007 of approximately \$7.2 million. During 2008, additional Oklahoma tax credits of approximately \$16.5 million were generated or purchased by the Company. The Company currently believes that approximately \$5.6 million of these state tax credit amounts will be utilized in the 2008 tax year and approximately \$18.1 million will be carried over to the 2009 tax year and later years. The Company's credits do not have an expiration date.

## 10. Common Equity

### Automatic Dividend Reinvestment and Stock Purchase Plan

In July 2005, the Company filed a Form S-3 Registration Statement to register 7,000,000 shares of the Company's common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan ("DRIP/DSPP"). Beginning in the third quarter of 2008, the Company began issuing authorized, but unissued shares of common stock to satisfy the common stock requirements of the DRIP/DSPP. During 2008, there were 262,193 shares of common stock issued to satisfy the common stock requirements of the DRIP/DSPP.

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 DRIP/DSPP and replace the July registration statement.

At December 31, 2008, there were 11,214,461 shares of unissued common stock reserved for issuance under various employee and Company stock plans.

### Equity Issuances

On November 20, 2008, OGE Energy entered into a Distribution Agreement (the "Agreement") with J.P. Morgan Securities Inc. ("JPMS"). Under the terms of the Agreement, OGE Energy could offer and sell up to 2,500,000 shares of its common stock from time to time through JPMS as principal or agent. Sales of the Company's common stock, if any, could be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices and in such other manner as agreed upon by OGE Energy and JPMS. JPMS received from OGE Energy a commission of 1.5 percent based on the gross sales price for any shares sold to or through it as principal or agent under the Agreement. Since inception of the Agreement on November 20, 2008 through December 31, 2008, the Company has sold 548,657 shares of its common stock under the Agreement. The Company has received net proceeds from JPMS of approximately \$13.7 million during this timeframe (after the JPMS commission of approximately \$0.2 million) related to the sale of the Company's common stock. From January 1, 2009 through January 28, 2009, the Company has sold 1,086,100 shares of its common stock under the Agreement. The Company has 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 has 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 Agreement pursuant to the terms of the 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.

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

<small>(In millions, year ended December 31)</small>	<b>2008</b>	2007	2006
<b>Average common shares outstanding</b>			
Basic average common shares outstanding	<b>92.4</b>	91.7	91.0
Effect of dilutive securities:			
Employee stock options and unvested stock grants	<b>0.1</b>	0.3	0.3
Contingently issuable shares (performance units)	<b>0.3</b>	0.5	0.8
Diluted average common shares outstanding	<b>92.8</b>	92.5	92.1
Anti-dilutive shares excluded from EPS calculation	-	-	0.1

## 11. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2008, the Company was in compliance with all of its debt agreements.

### Optional Redemption of Long-Term Debt

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
1.40% – 8.35% <sup>(A)</sup>	Garfield Industrial Authority, January 1, 2025	\$ 47.0
1.24% – 8.14% <sup>(A)</sup>	Muskogee Industrial Authority, January 1, 2025	32.4
1.35% – 7.75% <sup>(A)</sup>	Muskogee Industrial Authority, June 1, 2027	55.9
Total (redeemable during next 12 months)		\$135.3

<sup>(A)</sup> During the first six months of 2008, the interest rates for the Bonds were between 1.24% and 3.45%. In September 2008, the interest rates for the Bonds significantly increased to a one-week high of 8.35%. Currently, the interest rates for the Bonds are between 0.55% and 0.95%.

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

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

### Long-Term Debt Maturities

Other than the January 2010 maturity of Enogex's long-term debt discussed below, there are no maturities of the Company's long-term debt during 2010. Also, there are no maturities of the Company's long-term debt in years 2009, 2011 or 2012. Other than any outstanding balance under Enogex's revolving credit facility (discussed below), which matures in 2013, there are no maturities of the Company's long-term debt during 2013. At December 31, 2008, there was \$120.0 million outstanding under Enogex's revolving credit facility.

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

### Issuance of Long-Term Debt

In January 2008, OG&E issued \$200 million of 6.45% senior notes due February 1, 2038. The proceeds from the issuance were used to repay commercial paper borrowings. OG&E entered into two separate treasury lock arrangements, effective November 16, 2007 and November 19, 2007, to hedge interest payments on the first \$50.0 million and \$25.0 million, respectively, of the long-term debt that was issued in January 2008. These treasury lock agreements were settled on January 29, 2008.

On April 1, 2008, Enogex entered into a \$250 million unsecured five-year revolving credit facility. Subject to certain limitations, the facility provides Enogex with the option, exercisable annually, to extend the maturity of the facility for an additional year and, upon the expiration of the revolving term, an option to convert the outstanding balance under the facility to a one-year term loan. The facility provides the option for Enogex to increase the borrowing limit by up to an additional \$250 million (to a maximum of \$500 million) upon the agreement of the lenders (or any additional lender) and the satisfaction of other specified conditions. At December 31, 2008, there was \$120.0 million outstanding under the facility. These borrowings are not expected to be repaid within the next 12 months, therefore, they are classified as long-term debt for financial reporting purposes.

In September 2008, OG&E issued \$250 million of 6.35% senior notes due September 1, 2018. The proceeds from the issuance were used to fund a portion of the acquisition of the Redbud Facility. Pending such use, the proceeds were used to temporarily repay a portion of OG&E's outstanding commercial paper borrowings, as well as short-term borrowings from OGE Energy, both of which were incurred in part to fund OG&E's daily operational needs.

In December 2008, OG&E issued \$250 million of 8.25% senior notes due January 15, 2019. The proceeds from the issuance were used to repay borrowings under OG&E's term loan agreement with UBS AS, Stamford Branch and UBS Securities LLC, as discussed in Note 12, and the Company's and OG&E's revolving credit agreements, which were used to fund OG&E's daily operational needs as well as OG&E's acquisition of the Redbud Facility.

### Refinancing of Long-Term Debt

In late 2009, Enogex intends to refinance its \$400.0 million medium-term notes which mature in January 2010. Due to uncertainty in the current credit markets, at this time, Enogex cannot predict how interest rates will affect its ability to obtain financing on favorable terms

## 12. Short-Term Debt

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by loans under short-term bank facilities. The short-term debt balance was approximately \$298.0 million and \$295.8 million at December 31, 2008 and 2007, respectively, at a weighted-average interest rate of 0.75 percent and 5.54 percent, respectively. The following table shows the Company's revolving credit agreements and available cash at December 31, 2008.

(In millions)	Aggregate Commitment <sup>(A)</sup>	Amount Outstanding <sup>(B)</sup>	Weighted-Average Interest Rate	Maturity
<b>Revolving credit agreements and available cash</b>				
OGE Energy Corp. <sup>(C)</sup>	\$ 596.0	\$ 298.0	0.75% <sup>(F)</sup>	12/6/12 <sup>(E)</sup>
OG&E <sup>(D)</sup>	389.0	—	— <sup>(F)</sup>	12/6/12 <sup>(E)</sup>
Enogex <sup>(G)</sup>	250.0	120.0	1.86%	3/31/13 <sup>(E)</sup>
	1,235.0	418.0	1.07%	
Cash	174.4	N/A	N/A	N/A
<b>Total</b>	<b>\$1,409.4</b>	<b>\$418.0</b>	<b>1.07%</b>	

<sup>(A)</sup> All of the lenders that participate in OGE Energy's, OG&E's and Enogex's revolving credit agreements have funded their commitment, with the exception of Lehman Brothers Holdings, Inc. ("Lehman"), which filed for bankruptcy protection on September 15, 2008 and has not funded their portion of the revolving credit agreements. At December 31, 2008, approximately \$4 million and \$11 million, respectively, of OGE Energy's and OG&E's revolving credit agreements are not available as this portion was assigned to Lehman.

<sup>(B)</sup> Includes direct borrowings, outstanding commercial paper and letters of credit at December 31, 2008.

<sup>(C)</sup> 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, 2008, there was approximately \$298.0 million in outstanding borrowings under this revolving credit agreement. There were no outstanding commercial paper borrowings at December 31, 2008.

<sup>(D)</sup> 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, 2008, there were no outstanding borrowings under this revolving credit agreement and approximately \$0.3 million supporting letters of credit. There were no outstanding commercial paper borrowings at December 31, 2008.

<sup>(E)</sup> In December 2006, OGE Energy and OG&E amended and restated their revolving credit agreements to total in the aggregate \$1.0 billion, \$600 million for OGE Energy and \$400 million for OG&E. Each of the credit facilities has a five-year term with an option to extend the term for two additional one-year periods upon agreement of all banks participating in the revolving credit agreements. In November 2007, OGE Energy and OG&E utilized one of these one-year extensions to extend the maturity of their credit agreements to December 6, 2012. Also, each of these credit facilities has an additional option at maturity to convert the outstanding balance to a one-year term loan.

<sup>(F)</sup> Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements.

<sup>(G)</sup> On April 1, 2008, Enogex entered into a \$250 million unsecured five-year revolving credit facility. Subject to certain limitations, the facility provides Enogex with the option, exercisable annually, to extend the maturity of the facility for an additional year and, upon the expiration of the revolving term, an option to convert the outstanding balance under the facility to a one-year term loan. The facility provides the option for Enogex to increase the borrowing limit by up to an additional \$250 million (to a maximum of \$500 million) upon the agreement of the lenders (or any additional lender) and the satisfaction of other specified conditions. This bank facility is available to provide revolving credit borrowings. At December 31, 2008, Enogex had approximately \$120.0 million outstanding under this facility. These borrowings are not expected to be repaid within the next 12 months, therefore, they are classified as long-term debt for financial reporting purposes.

OGE Energy's and OG&E's ability to access the commercial paper market has been adversely impacted by the market turmoil since September 2008. Accordingly, in order to ensure the availability of funds, OGE Energy and OG&E utilized borrowings under their revolving credit agreements, which generally bear a higher interest rate and a minimum 30-day maturity compared to commercial paper, which has historically been available at lower interest rates and on a daily basis. However, in late 2008, OGE Energy's and OG&E's revolving credit borrowings had

a lower interest rate than commercial paper due to disruptions in the credit markets. OG&E also borrowed under the term loan agreements discussed below. In December 2008, OG&E repaid the outstanding borrowings under its revolving credit agreement with a portion of the proceeds received from the issuance of long-term debt in December. OG&E intends to utilize commercial paper in the commercial paper market when available. OGE Energy expects to repay the borrowings under its revolving credit agreement and begin utilizing the commercial paper market when available.

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

The Company had a commercial paper arrangement with Lehman, which filed for bankruptcy protection on September 15, 2008. On September 22, 2008, Barclays Plc purchased the investment banking and capital markets operations of Lehman and replaced Lehman as the commercial paper dealer in the Company's commercial paper arrangement. Also, the Company has a commercial paper arrangement with Wachovia Bank, National Association, which merged with Wells Fargo & Company on December 31, 2008.

On September 26, 2008, OG&E entered into a 10-day \$300 million term loan agreement with Royal Bank of Scotland PLC ("RBS"). On September 29, 2008, after OG&E purchased the entire partnership interest in the Redbud Facility, the Oklahoma Municipal Power Authority ("OMPA") and the Grand River Dam Authority ("GRDA") purchased their respective undivided interests in the Redbud Facility from OG&E for approximately \$417.5 million. After the closing of the sale of the undivided interests in the Redbud Facility, OG&E used the \$417.5 million in proceeds and repaid in full, on September 30, 2008, the \$300 million borrowed from RBS and invested the remainder of the proceeds in short-term investments which were recorded as Cash and Cash Equivalents on the Company's Consolidated Balance Sheet.

On September 26, 2008, OG&E entered into a \$200 million term loan agreement with UBS AS, Stamford Branch and UBS Securities LLC maturing March 26, 2010. This loan could be used for general corporate purposes and permitted acquisitions as defined in the loan agreement. On December 15, 2008, OG&E repaid the outstanding \$50.0 million balance and terminated this loan agreement.

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.

### **Omnibus Agreement**

Concurrent with the entry of the Enogex LLC credit facility on April 1, 2008, Enogex also entered into an omnibus agreement with OGE Energy. The omnibus agreement memorializes Enogex's obligation to reimburse OGE Energy for costs incurred on behalf of Enogex and its subsidiaries. Specifically, Enogex reimburses OGE Energy, subject to a maximum reimbursement, for: (i) the performance of general and administrative services for Enogex and its subsidiaries, such as legal, accounting, treasury, finance, investor relations, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, facilities, fleet management and media services; and (ii) the payment of certain operating expenses of Enogex and its subsidiaries, including for compensation and benefits of operating personnel. The reimbursement for certain operating expenses is not subject to the maximum reimbursement for general and administrative expenses.

### **Enogex Intercompany Borrowing Agreement**

On April 1, 2008, Enogex amended its intercompany borrowing agreement with OGE Energy to decrease the maximum amount permitted to be borrowed by Enogex from \$200 million to \$100 million. This agreement has a termination date of April 1, 2015. At December 31, 2008, there were no outstanding intercompany borrowings.

### **13. Retirement Plans and Postretirement Benefit Plans**

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

### **Defined Benefit Pension Plan**

All eligible employees of the Company and participating affiliates are covered by a non-contributory defined benefit pension plan. For employees hired on or after February 1, 2000, the pension plan is a cash balance plan, 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. Employees hired prior to February 1, 2000 will receive the greater of the cash balance benefit or

a benefit based primarily on years of service and the average of the five highest consecutive years of compensation during an employee's last ten 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.

It is the Company's policy to fund the plan on a current basis based on the net periodic SFAS No. 87, "Employers' Accounting for Pensions," pension expense as determined by the Company's actuarial consultants. Additional amounts may be contributed from time to time to increase the funded status of the plan. During both 2008 and 2007, 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 2009, the Company may contribute up to \$50.0 million to its pension plan. The expected contribution to the pension plan during 2009 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, 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.

At December 31, 2007, the projected benefit obligation and fair value of assets of the Company's pension plan and restoration of retirement income plan was approximately \$522.0 million and \$514.2 million, respectively, for an underfunded status of approximately \$7.8 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.

In accordance with SFAS No. 88, "Employer's Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," a one-time settlement charge is required to be recorded by an organization when lump-sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation or the retirement restoration benefit obligation during a plan year exceed the service cost and interest cost components of the organization's net periodic pension cost or retirement restoration

cost. During 2007, the Company experienced an increase in both the number of employees electing to retire and the amount of lump-sum payments to be paid to such employees upon retirement as well as the death of the Company's Chairman and Chief Executive Officer in September 2007. As a result, the Company recorded a pension settlement charge and a retirement restoration plan settlement charge in 2007. The Company did not record a pension settlement charge during 2008. 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 <sup>(A)</sup>	Enogex	OGE Energy	Total
<b>Pension settlement charge:</b>				
2007	\$13.3	\$0.5	\$2.9	\$16.7
<b>Retirement restoration plan settlement charge:</b>				
2007	\$ 0.1	–	\$2.2	\$ 2.3

<sup>(A)</sup> OG&E's Oklahoma 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. Among other things, it alters the manner in which pension plan assets and liabilities are valued for purposes of calculating required pension contributions, introduces a new funding requirement for single- and multi-employer defined benefit pension plans, provides legal certainty on a prospective basis for cash balance and other hybrid plans and addresses contributions to defined contribution plans, deduction limits for contributions to retirement plans and investment advice provided to plan participants.

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. While the Company generally has until the last day of the first plan year beginning in 2009 to reflect those changes as part of the plan document, plans must nevertheless comply in operation as of each provision's effective date. In order to be in compliance with the Pension Protection Act, the Company has implemented the following changes to its defined benefit pension plan and defined contribution plan, as applicable: (i) effective January 1, 2008, the Company's defined benefit pension plan and defined contribution plans were amended to incorporate clarifying provisions and changes relating to the Pension Protection Act notice requirements and allow a non-spouse beneficiary to directly rollover an eligible distribution to an eligible individual retirement account ("IRA") or to a Roth IRA; (ii) effective January 1, 2008, the Company's defined benefit pension plan and defined contribution plans were amended to provide 100 percent vesting after completing three years of service; (iii) for the Company's defined benefit pension plan, effective

January 1, 2008, that plan was amended to incorporate the new Pension Protection Act applicable mortality table and applicable interest rate under Internal Revenue Code Section 417(e)(3) for determining the actuarial equivalent value of a benefit that is converted to a lump sum; (iv) for the Company's defined contribution plan, effective January 1, 2008, that plan was amended to provide, in accordance with the Pension Protection Act that participants under age 55 may diversify amounts held in his/her TRASOP account out of the OGE Energy Corp Common Stock Fund into other investment funds; and (v) for the Company's defined contribution plan, that plan was amended to implement an eligible automatic contribution arrangement and provide for a qualified default investment alternative consistent with the Department of Labor regulations. 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's assets consist primarily of investments in mutual funds, U.S. Government securities, listed common stocks and corporate debt. The following table shows, by major category, the percentage of the fair value of the plan assets held at December 31, 2008 and 2007:

(December 31)	2008	2007
Equity securities	45%	61%
Debt securities	53%	37%
Other	2%	2%
Total	100%	100%

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 plan assets:

Asset Class	Target Allocation	Minimum	Maximum
Domestic equity	30%	–%	60%
Domestic mid-cap equity	10%	–%	10%
Domestic small-cap equity	10%	–%	10%
International equity	10%	–%	10%
Fixed income domestic	38%	30%	70%
Cash	2%	–%	5%

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	Lehman 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 Investors Service ("Moody's"), Standard & Poor's or Fitch Ratings. The portfolio may invest up to ten 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-capitalization 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 (ten 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.

#### 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 \$58.2 million in 2009, \$59.6 million in 2010, \$62.0 million in 2011, \$65.2 million in 2012, \$64.3 million in 2013 and an aggregate of approximately \$289.2 million in years 2014 to 2018. 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 ten 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 SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions," costs and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

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.

At December 31, 2007, the accumulated postretirement benefit obligation and fair value of assets of the Company's postretirement benefit plans was approximately \$216.8 million and \$78.5 million, respectively, for an underfunded status of approximately \$138.3 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 9.0 percent in 2009 with the rates decreasing in subsequent years by one percentage point per year through 2012. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

(In millions, year ended December 31)	2008	2007	2006
<b>One-percentage point increase</b>			
Effect on aggregate of the service and interest cost components	\$ 2.2	\$ 2.3	\$ 2.2
Effect on accumulated postretirement benefit obligations	28.3	26.9	29.2
<b>One-percentage point decrease</b>			
Effect on aggregate of the service and interest cost components	\$ 1.8	\$ 1.9	\$ 1.8
Effect on accumulated postretirement benefit obligations	23.4	22.2	24.0

#### 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 plan benefit obligation ("APBO") for the Company with respect to its postretirement medical plan will be reduced by approximately \$70.9 million as a result of savings to the Company with respect to its postretirement medical plan resulting from the Medicare Act provided subsidy, which will reduce the Company's costs for its postretirement medical plan by approximately \$5.6 million annually. The \$5.6 million in annual savings is comprised of a reduction of approximately \$2.4 million from amortization of the \$70.9 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately \$2.6 million and a reduction in the service cost due to the subsidy of approximately \$0.6 million.

The Company expects to pay gross benefits payments related to its postretirement benefit plans, including prescription drug benefits, of approximately \$13.2 million in 2009, \$14.3 million in 2010, \$15.5 million in 2011, \$16.4 million in 2012, \$17.3 million in 2013 and an aggregate of approximately \$96.1 million in years 2014 to 2018. The Company expects to receive Federal subsidy receipts provided by the Medicare Act of approximately \$1.6 million in 2009, \$1.8 million in 2010, \$2.0 million in 2011, \$2.2 million in 2012, \$2.3 million in 2013 and an aggregate of approximately \$14.0 million in years 2014 to 2018. The Company received approximately \$0.8 million in Federal subsidy receipts in 2008.

## 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 2008 and 2007. 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 benefit obligation. The accumulated benefit obligation 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, 2008 was approximately \$485.1 million and \$4.8 million, respectively. The accumulated benefit obligation for the pension plan and the restoration of retirement income plan at December 31, 2007 was approximately \$459.0 million and \$2.9 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:

(In millions, December 31)	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
	2008	2007	2008	2007	2008	2007
<b>Change in benefit obligation</b>						
Beginning obligations	<b>\$(518.0)</b>	\$(575.2)	<b>\$(4.0)</b>	\$(9.8)	<b>\$(216.8)</b>	\$(225.4)
Service cost	<b>(19.0)</b>	(20.6)	<b>(0.7)</b>	(0.6)	<b>(3.7)</b>	(4.0)
Interest cost	<b>(31.4)</b>	(31.8)	<b>(0.4)</b>	(0.5)	<b>(13.4)</b>	(12.4)
Plan changes	-	16.7	-	0.1	-	-
Participants' contributions	-	-	-	-	<b>(6.0)</b>	(5.5)
Actuarial gains (losses)	<b>(19.5)</b>	15.4	<b>(2.7)</b>	(1.4)	<b>(9.2)</b>	15.2
Benefits paid	<b>40.9</b>	77.5	<b>0.5</b>	8.2	<b>14.8</b>	15.3
Ending obligations	<b>\$(547.0)</b>	\$(518.0)	<b>\$(7.3)</b>	\$(4.0)	<b>\$(234.3)</b>	\$(216.8)
<b>Change in plans' assets</b>						
Beginning fair value	<b>514.2</b>	519.4	-	-	<b>78.5</b>	74.0
Actual return on plans' assets	<b>(133.4)</b>	22.3	-	-	<b>(19.2)</b>	5.6
Employer contributions	<b>50.0</b>	50.0	<b>0.5</b>	8.2	<b>6.5</b>	8.7
Participants' contributions	-	-	-	-	<b>6.0</b>	5.5
Benefits paid	<b>(40.9)</b>	(77.5)	<b>(0.5)</b>	(8.2)	<b>(14.8)</b>	(15.3)
Ending fair value	<b>389.9</b>	514.2	-	-	<b>57.0</b>	78.5
Funded status at end of year	<b>\$(157.1)</b>	\$(3.8)	<b>\$(7.3)</b>	\$(4.0)	<b>\$(177.3)</b>	\$(138.3)

## Net Periodic Benefit Cost

(In millions, year ended December 31)	Pension Plan			Restoration of Retirement Income Plan			Postretirement Benefit Plans		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
Service cost	<b>\$ 19.0</b>	\$ 20.6	\$ 19.7	<b>\$0.8</b>	\$0.6	\$0.7	<b>\$ 3.7</b>	\$ 4.0	\$ 3.7
Interest cost	<b>31.4</b>	31.8	30.3	<b>0.4</b>	0.5	0.5	<b>13.4</b>	12.4	11.9
Return on plan assets	<b>(43.7)</b>	(43.9)	(38.4)	-	-	-	<b>(6.5)</b>	(5.9)	(5.6)
Amortization of transition obligation	-	-	-	-	-	-	<b>2.7</b>	2.7	2.7
Amortization of net loss	<b>9.3</b>	10.5	16.5	<b>0.3</b>	0.2	0.2	<b>4.0</b>	6.1	8.7
Amortization of recognized prior service cost	<b>0.9</b>	5.2	5.2	<b>0.6</b>	0.6	0.7	<b>1.9</b>	2.1	2.1
Settlement	-	16.7	17.1	-	2.3	-	-	-	-
Net periodic benefit cost <sup>(A)</sup>	<b>\$ 16.9</b>	\$ 40.9	\$ 50.4	<b>\$2.1</b>	\$4.2	\$2.1	<b>\$19.2</b>	\$21.4	\$23.5

<sup>(A)</sup> In addition to the \$19.0 million and \$45.1 million in SFAS No. 87 net periodic benefit cost recognized in 2008 and 2007, respectively, OG&E also recognized an expense of approximately \$10.1 million and a gain of approximately \$10.1 million, respectively, related to the reversal of a portion of the regulatory asset identified as Deferred Pension Plan Expenses (see Note 1). The capitalized portion of the net periodic pension benefit cost was approximately \$4.0 million, \$5.5 million and \$7.6 million at December 31, 2008, 2007 and 2006, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately \$4.6 million, \$4.8 million and \$5.0 million at December 31, 2008, 2007 and 2006, respectively.

## Rate Assumptions

(Year ended December 31)	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
	2008	2007	2006	2008	2007	2006
Discount rate	<b>6.25%</b>	6.25%	5.75%	<b>6.25%</b>	6.25%	5.75%
Rate of return on plans' assets	<b>8.50%</b>	8.50%	8.50%	<b>8.50%</b>	8.50%	8.50%
Compensation increases	<b>4.50%</b>	4.50%	4.50%	<b>4.50%</b>	4.50%	4.50%
Assumed health care cost trend:						
Initial trend	<b>N/A</b>	N/A	N/A	<b>9.00%</b>	9.00%	9.00%
Ultimate trend rate	<b>N/A</b>	N/A	N/A	<b>4.50%</b>	4.50%	4.50%
Ultimate trend year	<b>N/A</b>	N/A	N/A	<b>2014</b>	2013	2012

N/A - not applicable



The overall expected rate of return on plan assets assumption remained at 8.50 percent in 2007 and 2008 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 \$2.1 million and \$1.6 million at December 31, 2008 and 2007, respectively.

#### **Defined Contribution Plan**

The Company provides a defined contribution savings plan. Each regular full-time employee of the Company or a participating affiliate is eligible to participate in the plan immediately. All other employees of the Company or a participating affiliate are eligible to become participants in the plan after completing one year of service as defined in the plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the plan, for that pay period. Contributions of the first six percent of compensation are called "Regular Contributions" and any contributions over six percent of compensation are called "Supplemental Contributions." 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 Company contributes to the plan each pay period on behalf of each participant an amount equal to 50 percent of the participant's Regular Contributions for participants whose employment or re-employment date, as defined in the plan, occurred before February 1, 2000 and who have less than 20 years of service, as defined in the plan, and an amount equal to 75 percent of the participant's Regular Contributions for participants whose employment or re-employment date occurred before February 1, 2000 and who

have 20 or more years of service. For participants whose employment or re-employment date occurred on or after February 1, 2000, the Company contributes 100 percent of the Regular Contributions deposited during such pay period by such participant. No Company contributions are made with respect to a participant's Supplemental Contributions, Catch-Up Contributions, rollover contributions, or with respect to a participant's Regular 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. The Company's contribution, which is initially allocated for investment to the OGE Energy Corp. Common Stock Fund, may be made in shares of the Company's common stock or in cash which is used to invest in the Company's common stock. Once made, the Company's contribution may be reallocated, on any business day, by participants to other available investment options. The Company contributed approximately \$8.6 million, \$7.6 million and \$6.8 million during 2008, 2007 and 2006, respectively, to the defined contribution plan.

#### **Deferred Compensation Plan**

The Company provides a deferred compensation 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' defined contribution 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 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 defined contribution plan with such deferrals to start when maximum deferrals to the qualified defined contribution 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 provide for the match that would have been made under the defined contribution plan had such deferrals been made under that plan without regard to the statutory limitations on elective deferrals and matching contributions applicable to the defined contribution 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. The supplemental executive retirement plan is intended to be an unfunded plan and not subject to the benefit limits imposed by the Code.

## 14. 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, 2008, 2007 and 2006.

(In millions)	Electric Utility	Transportation and Storage <sup>(B)</sup>	Gathering and Processing <sup>(B)</sup>	Marketing	Other Operations	Eliminations	Total
<b>2008</b>							
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 <sup>(A)</sup>	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
<b>2007</b>							
Operating revenues	\$ 1,835.1	\$ 529.1	\$ 799.4	\$ 1,541.2	\$ -	\$ (907.2)	\$ 3,797.6
Cost of goods sold	1,025.1	396.4	603.5	1,513.4	-	(903.7)	2,634.7
Gross margin on revenues	810.0	132.7	195.9	27.8	-	(3.5)	1,162.9
Other operation and maintenance	320.7	48.5	72.1	10.1	(11.3)	(3.3)	436.8
Depreciation and amortization	141.3	17.0	28.7	0.2	8.1	-	195.3
Impairment of assets	-	0.5	-	-	-	-	0.5
Taxes other than income	56.0	11.7	3.7	0.4	3.2	-	75.0
Operating income	\$ 292.0	\$ 55.0	\$ 91.4	\$ 17.1	\$ -	\$ (0.2)	\$ 455.3
Total assets	\$ 3,874.9	\$ 1,519.3	\$ 931.4	\$ 253.2	\$ 2,297.6	\$ (3,638.6)	\$ 5,237.8
Capital expenditures	\$ 377.3	\$ 49.0	\$ 125.0	\$ 0.2	\$ 14.5	\$ (8.3)	\$ 557.7
<b>2006</b>							
Operating revenues	\$ 1,745.7	\$ 508.7	\$ 704.3	\$ 1,941.3	\$ -	\$ (894.4)	\$ 4,005.6
Cost of goods sold	950.0	383.1	536.7	1,927.1	-	(894.4)	2,902.5
Gross margin on revenues	795.7	125.6	167.6	14.2	-	-	1,103.1
Other operation and maintenance	316.5	41.2	59.5	9.3	(9.9)	-	416.6
Depreciation and amortization	132.2	17.9	24.2	0.2	6.9	-	181.4
Impairment of assets	-	-	0.3	-	-	-	0.3
Taxes other than income	53.1	11.8	3.8	0.4	3.0	-	72.1
Operating income	\$ 293.9	\$ 54.7	\$ 79.8	\$ 4.3	\$ -	\$ -	\$ 432.7
Total assets	\$ 3,589.7	\$ 1,441.2	\$ 843.7	\$ 231.4	\$ 1,968.8	\$ (3,176.4)	\$ 4,898.4
Capital expenditures	\$ 411.1	\$ 9.8	\$ 57.6	\$ -	\$ 8.4	\$ (0.3)	\$ 486.6

<sup>(A)</sup> 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.

<sup>(B)</sup> 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.

## 15. 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)	2009	2010	2011	2012	2013	2014 and Beyond
Operating lease obligations						
OG&E railcars	\$3.9	\$3.8	\$38.0	\$ –	\$ –	\$ –
Enogex noncancellable operating leases	4.2	2.5	1.6	0.4	–	–
Total operating lease obligations	\$8.1	\$6.3	\$39.6	\$0.4	\$ –	\$ –

Payments for operating lease obligations were approximately \$7.3 million, \$6.7 million and \$7.6 million in 2008, 2007 and 2006, respectively.

### OG&E Railcar Lease Agreement

At December 31, 2007, OG&E had a noncancellable operating lease with purchase options, covering 1,409 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. On December 29, 2005, OG&E entered into a new lease agreement for railcars effective February 1, 2006 with a new lessor as described below. In April 2008, OG&E amended its contract to add 55 new railcars for approximately \$3.5 million. At the end of the new 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. In mid-February 2009, OG&E expects to enter into a new short-term lease agreement to add 270 new railcars for approximately \$1.2 million to satisfy the requirements of its new coal transportation contracts with BNSF Railway and Union Pacific as discussed below. The expiration dates of the lease agreement are expected to be: (i) six months from the effective date of the lease agreement for 135 cars and (ii) one year from the effective date of the lease agreement for the other 135 cars. OG&E is also required to maintain 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. OG&E has 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. The timing of the completion of this proceeding is uncertain at this time. The effect of the new BNSF Railway agreement and the anticipated rail rate prescription

from the STB for rail transportation to OG&E's Sooner and Muskogee power plants is expected to cause an approximate 50 percent increase in OG&E's delivered coal prices.

### Public Utility Regulatory Policy Act of 1978

At December 31, 2008, 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.

During 2008, 2007 and 2006, OG&E made total payments to cogenerators of approximately \$152.8 million, \$156.8 million and \$162.6 million, respectively, of which approximately \$84.4 million, \$88.9 million and \$94.9 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: 2009 – \$86.8 million, 2010 – \$85.0 million, 2011 – \$83.1 million, 2012 – \$81.0 million and 2013 – \$81.0 million.

### Fuel Minimum Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of approximately \$215.1 million, \$190.2 million and \$195.1 million for the years ended December 31, 2008, 2007 and 2006, respectively. OG&E has entered into purchase commitments of necessary fuel supplies of approximately: 2009 – \$320.7 million, 2010 – \$114.1 million, 2011 – \$65.2 million, 2012 – \$3.9 million, 2013 – \$3.9 million and 2014 and Beyond – \$19.5 million.

### **Natural Gas Units**

In August 2008, OG&E issued a request for proposal (“RFP”) for gas supply purchases for periods from November 2008 through March 2009, which accounted for approximately 15 percent of its projected 2009 natural gas requirements. The contracts resulting from this RFP are tied to various gas price market indices that will expire in 2009. Additional gas supplies to fulfill OG&E’s remaining 2009 natural gas requirements will be acquired through additional RFPs in early to mid-2009, along with monthly and daily purchases, all of which are expected to be made at market prices.

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

Cheyenne Plains Gas Pipeline Company, L.L.C. (“Cheyenne Plains”) operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas with a capacity of 730,000 decatherms/day (“Dth/day”). OERI entered into a Firm Transportation Service Agreement (“FTSA”) with Cheyenne Plains in 2004, for 60,000 Dth/day of firm capacity on the Cheyenne Plains 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 through 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 2009 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 ten years (subject to possible extension) that would give 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 includes construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Enogex currently estimates that its capital expenditures related to this project will be approximately \$94 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 to MEP. Further, the FERC order rejected all claims raised by protestors regarding the lease agreement. Accordingly, Enogex is proceeding with the construction of facilities necessary to implement this service. On August 25, 2008, one protestor filed a request for rehearing. The FERC has not yet ruled on the request for rehearing and the current timing of any FERC action cannot be reasonably predicted. The MEP project is currently expected to be in service during the second quarter of 2009.

### **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 is a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the Federal government, alleges: (a) each of the named defendants have improperly or intentionally mismeasured gas (both volume and British thermal unit (“Btu”) content) purchased from Federal and Indian lands which have resulted in the under reporting and underpayment of gas royalties owed to the Federal government; (b) certain provisions generally found in gas purchase contracts are improper; (c) transactions by affiliated companies are not arms-length; (d) excess processing cost deduction; and (e) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys’ fees.

In qui tam actions, the Federal government can intervene and take over such actions from the relator. The Department of Justice, on behalf of the Federal government, decided not to intervene in this action.

The plaintiff filed over 70 other cases naming over 300 other defendants in various Federal courts across the country containing nearly identical allegations. The Multidistrict Litigation Panel entered its order in late 1999 transferring and consolidating for pretrial purposes approximately 76 other similar actions filed in nine other Federal courts. The consolidated cases are now before the U.S. District Court for the District of Wyoming.

In October 2002, the court granted the Department of Justice’s motion to dismiss certain of the plaintiff’s claims and issued an order dismissing the plaintiff’s valuation claims against all defendants. Various procedural motions have been filed. A hearing on the defendants’ motions to dismiss for lack of subject matter jurisdiction, including public disclosure, original source and voluntary disclosure requirements was held in 2005 and the special master ruled that OG&E and all Enogex parties named in these proceedings should be dismissed. This ruling was appealed to the District Court of Wyoming.

On October 20, 2006, the District Court of Wyoming ruled on Grynberg’s appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex Services Corp., Transok, Inc. and OG&E, for lack of subject matter jurisdiction. Judgment was entered on November 17, 2006 and Grynberg filed his notice of appeal with the District Court of Wyoming. The defendants filed motions for attorneys’ fees on various bases January 8, 2007. The defendants also filed for other legal costs on December 18, 2006. A hearing on these motions was held on April 24,

2007, at which time the judge took these motions under advisement. Grynberg has also filed appeals with the Tenth Circuit Court of Appeals. In compliance with the Tenth Circuit's June 19, 2007 scheduling order, Grynberg filed appellants' opening brief on July 31, 2007 and the appellees' consolidated response briefs were filed on November 21, 2007. Also, on December 5, 2007, the Company filed a notice of its intent to file a separate response brief, which the Company filed on January 11, 2008. Oral arguments were made to the Tenth Circuit on September 25, 2008. No ruling was made on the oral arguments and the court took the case under advisement. 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 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 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.

On July 2, 2007, the court ordered the plaintiffs and defendants to file proposed findings of facts and conclusions of law on class certification by July 31, 2007. On July 31, 2007, the two subsidiary entities of the Company filed their proposed findings of fact and conclusions of law regarding conflict of law issues and the coordinated defendants filed their proposed findings of facts and conclusions of law on class certification.

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.

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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 Co. (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.

#### **OERI Self-Disclosure Matter**

On November 13, 2007, OERI orally self-reported to the FERC Office of Enforcement ("OE") a three-month transaction that occurred in 2005 ("Transaction") between OERI and an unaffiliated third party. OERI reported, based on its initial findings, that the Transaction may have violated the FERC's shipper-must-have-title policy and the maximum rate cap applicable to natural gas transportation. OERI conducted an internal investigation into the Transaction and in December 2007, at the OE's request, OERI provided a written report to the OE of that internal investigation. Subsequently, the OE advised OERI that it had commenced a preliminary, non-public investigation into compliance matters relating to the Transaction. In February 2008, the OE submitted to OERI discovery requests relating to various aspects of the Transaction and OERI's internal investigation. OERI responded to the discovery requests at the end of February 2008. OERI also informed the OE that it was continuing to review other transactions to determine whether any additional transactions may have violated the FERC's capacity release rules. On February 2, 2009, following informal conferences with the OE, OERI submitted a written summary of two additional transactions that presented possible compliance issues relating to the FERC's capacity release rules. The OE notified OERI on February 6, 2009 with a notification that it had decided to terminate its investigation without any remedial or other action regarding any of the three transactions reported. This matter is now considered closed.

#### **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. It is anticipated that third-party damages related to this incident will not be material to the Company.

#### **Franchise Fee Lawsuit**

On June 19, 2006, two OG&E customers brought a putative class action, on behalf of all similarly situated customers, in the District Court of Creek County, Oklahoma, challenging certain charges on OG&E's electric bills. The plaintiffs claim that OG&E improperly charged sales tax based on franchise fee charges paid by its customers. The plaintiffs also challenge certain franchise fee charges, contending that such fees are more than is allowed under Oklahoma law. OG&E's motion for summary judgment was denied by the trial judge. OG&E filed a writ of prohibition at the Oklahoma Supreme Court asking the court to direct the trial court to

dismiss the class action suit. In January 2007, the Oklahoma Supreme Court "arrested" the District Court action until, and if, the propriety of the complaint of billing practices is determined by the OCC. In September 2008, the plaintiffs filed an application with the OCC asking the OCC to modify its order which authorizes OG&E to collect the challenged franchise fee charges. A procedural schedule and notice requirements for the matter were established by the OCC on December 4, 2008. The OCC expects to hear arguments for a motion to dismiss on March 26, 2009. OG&E believes that this case 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 plaintiff 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. OG&E expects the arbitration to occur in the first half of 2009. 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.

#### **Potential Collateral Requirements**

In the event Moody's or Standard & Poor's were to lower the Company's senior unsecured debt rating to a below investment grade rating, at December 31, 2008, the Company would have been required to post approximately \$0.9 million of collateral to satisfy its obligation under its financial and physical contracts. 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.

#### **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 as well as 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 impose strict, joint and several 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 ("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 \$1.6 million and \$32.1 million, respectively of the Company's capital expenditures budgeted for 2009 and 2010 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 to preserve and enhance environmental quality will be approximately \$40.0 million during 2009 as compared to approximately \$40.7 million in 2008. The Company 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**

On March 15, 2005, the U.S. Environmental Protection Agency ("EPA") issued the Clean Air Mercury Rule ("CAMR") to limit mercury emissions from coal-fired boilers. On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit Court vacated the rule. Various petitions and appeals related to this decision have been made and are not yet resolved. On February 6, 2009, the EPA filed a motion to dismiss their earlier request for the U.S. Supreme Court to review the 2008 decision. Industry interests are still seeking the U.S. Supreme Court review in the case. The EPA has stated that it intends to draft mercury rules under the Federal Clean Air Act. The Company cannot predict the outcome of the Federal litigation at this time. Until the rule was vacated, the CAMR required mercury monitoring to begin in 2009. Accordingly, OG&E installed mercury monitoring equipment on all five of its coal units. The cost of the monitoring equipment was approximately \$5.0 million in 2007 and approximately \$0.4 million in 2008. Because the CAMR litigation

is ongoing, the cost to install mercury controls is uncertain at this time but may be significant, particularly if the EPA develops more stringent requirements. Because of the uncertainty caused by the litigation regarding the CAMR, the promulgation of an Oklahoma rule that would apply to existing facilities has been delayed. OG&E will continue to participate in the state rule making process.

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 has joined with eight other central states to address these visibility impacts.

In September 2005, the Oklahoma Department of Environmental Quality ("ODEQ") informally notified affected utilities that they would be required to perform a study to determine their impact on visibility in Federal Class I areas. Affected utilities are those which have "Best Available Retrofit Technology ("BART") eligible sources" (sources built between 1962 and 1977). For OG&E, these include various generating units at various generating stations. Regulations, however, allow an owner or operator of a BART-eligible source to request and obtain a waiver from BART if modeling shows no significant impact on visibility in nearby Class I areas. Based on this modeling, the ODEQ made a preliminary determination to accept an application for a waiver for the Horseshoe Lake generating station. The Horseshoe Lake waiver is expected to be included in the ODEQ state implementation plan.

The modeling did not support waivers for the affected 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 nitrogen oxide ("NOX") controls on all three units. At the same time, OG&E submitted a determination to the ODEQ that an alternative compliance plan for the affected units at the Muskogee and Sooner power plants will achieve overall greater visibility improvement than BART in the affected Class I areas and the alternative plan extends the timeline for compliance to 2018. The cost for this alternative compliance plan, including the BART compliance plan for the Seminole power plant (the alternative compliance plan and the BART compliance plan are collectively referred to herein as the "alternative plan"), was estimated at approximately \$470 million in March 2007. The alternative plan included installing semi-dry scrubbers on three of four affected coal units and low NOX burner equipment on all four coal units. This alternative plan was subject to approval by the ODEQ and the EPA. The EPA provided comments to the ODEQ on OG&E's alternative plan. On November 16, 2007, the ODEQ notified OG&E that additional analysis would be required before the OG&E alternative plan could be accepted. On May 30, 2008, OG&E filed the results with the ODEQ for the affected generating units as well as withdrawing its alternative plan filed in March 2007. In the May 30, 2008 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 its four coal-fired generating units at its Muskogee and Sooner generating stations. The capital expenditures

associated with the installation of the low NOX combustion technology are expected to be approximately \$110 million. OG&E believes that these control measures will achieve visibility improvements in a cost-effective manner. OG&E did not propose the installation of scrubbers at its four coal-fired generating units because OG&E concluded that, consistent with the EPA's regulations on BART, the installation of scrubbers (at an estimated cost of \$1.7 billion) would not be cost-effective. OG&E previously reported an expectation that a compliance plan would be approved by the EPA by December 31, 2008; however, submission of the overall compliance plan by the ODEQ (which will include OG&E's compliance plan previously submitted to the ODEQ) has been delayed and the current timing of the EPA approval cannot be reasonably predicted. In a letter dated November 4, 2008, the EPA notified the ODEQ that they had completed their review of BART applications for all affected sources in Oklahoma, which included OG&E. The EPA did not approve or disapprove the applications, however, additional information was requested from the ODEQ by the EPA regarding OG&E's plan. The Company cannot predict what action the EPA or the ODEQ will take in response to OG&E's May 30, 2008 filing or the November 4, 2008 letter from the EPA. Until the compliance plan is approved, the total cost of compliance, including capital expenditures, cannot be estimated by OG&E with a reasonable degree of certainty. OG&E expects that any necessary environmental expenditures 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.

The original deadline for the ODEQ to submit a state implementation plan for regional haze that includes final BART determinations was December 17, 2007. The ODEQ did not meet this deadline. On January 15, 2009, the EPA published a rule that gives the ODEQ two years to complete the state implementation plan. If the ODEQ fails to meet this deadline, the EPA can issue a Federal implementation plan.

The 1990 Clean Air Act includes an acid rain program to reduce sulfur dioxide ("SO<sub>2</sub>") 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 SO<sub>2</sub> released from the chimney. Plants may only release as much SO<sub>2</sub> as they have allowances. Allowances may be banked and traded or sold nationwide. Beginning in 2000, OG&E became subject to more stringent SO<sub>2</sub> 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 2008, OG&E's SO<sub>2</sub> emissions were below the allowable limits.

The EPA allocated SO<sub>2</sub> allowances to OG&E starting in 2000 and OG&E started banking allowances in 2001. OG&E sold no banked allowances in 2008. Also, during 2008, OG&E received proceeds of approximately \$0.4 million from the annual EPA spot (year 2008) and seven-year advance (year 2015) allowance auctions that were held in March 2008.

With respect to the NOX regulations of the acid rain program, OG&E committed to meeting a 0.45 lbs/million British thermal unit ("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 2008 were approximately 0.32 lbs/MMBtu. It is expected that NOX emissions will be further reduced to 0.15 lbs/MMBtu by 2016 if the regional haze compliance plan discussed above is approved by the EPA. Further reductions in NOX emissions could be required if the ODEQ determines that such NOX emissions are impacting the air quality of the Tulsa or Oklahoma City metropolitan areas, or if Oklahoma becomes non-attainment with the fine particulate standard. Any of these scenarios would likely require significant capital and operating expenditures.

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.

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 has 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 is expected to determine a final designation by March 2010. States will 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 are the most likely areas to be designated non-attainment in Oklahoma. The Company cannot predict the final outcome of this evaluation or its timing or affect on OG&E's or Enogex's operations.

On April 25, 2005, the EPA published a finding that all 50 states failed to submit the interstate pollution transport plans required by the 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 the state to the EPA on May 7, 2007, and additional information was submitted by the state to EPA on December 5, 2007. Assuming the state implementation plan is approved as submitted, there should be no significant adverse impact to OG&E as a result of the April 25, 2005 finding. The date of EPA approval of Oklahoma's demonstration is currently unknown.

In July 2008, OG&E received a request for information from the EPA regarding 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 Clean Air Act's new source review process. OG&E believes it has acted in full compliance with the 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.

At December 31, 2008, OG&E had received Title V permits for all of its generating stations and intends to continue to renew these permits as necessary. In January 2008, the ODEQ proposed fee increases of approximately 28 percent for Title V sources and 13 percent for minor sources. These fee increases were approved and became effective July 1, 2008. Air permit fees for OG&E's generating stations were approximately \$0.8 million in 2008 and for Enogex's facilities were approximately \$0.3 million in 2008.

In addition to the requirements related to emissions of SO<sub>2</sub>, NO<sub>x</sub> and mercury discussed above, 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, including a recent U.S. Supreme Court decision holding that the EPA has the authority to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act. Increased pressure for carbon dioxide emissions reduction also is coming from investor organizations and the international community.

On the legislative front, in June 2005, the U.S. Senate adopted a resolution declaring that mandatory reductions in greenhouse gases are needed. Despite executive branch opposition to any mandatory requirements, several bills that would cap or tax greenhouse gases from electric utilities are being considered by Congress, and the concept of such regulation has received support from the majority leadership in both the U.S. Senate and U.S. House of Representatives.

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 our future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

#### **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 2008, OG&E obtained refunds of approximately \$2.2 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 received two Oklahoma Pollutant Discharge Elimination System ("OPDES") renewal permits in February 2008 from the state of Oklahoma. OG&E filed an OPDES renewal application with the state of Oklahoma on August 4, 2008 for its Seminole power plant and received a draft permit for review on January 9, 2009. OG&E is currently reviewing this draft permit to determine if it is reasonable in its requirements and allows operational flexibility.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the "best available technology" for minimizing environmental impacts. The EPA Section 316(b) rules for existing facilities became effective July 23, 2004. On January 25, 2007, a Federal court reversed and remanded certain portions of the Section 316(b) rules to the EPA. On July 9, 2007, the EPA suspended these portions of the Section 316(b) rules for existing facilities. As a result of such suspension, permits required for existing facilities are to be developed by the individual states using their best professional judgment until the EPA completes its review of the suspended sections. In September 2007, the state of Oklahoma required a comprehensive demonstration study be submitted by January 7, 2008 for each affected facility. On January 7, 2008, OG&E submitted the requested studies for its facilities. Additionally, on April 14, 2008, the U.S. Supreme Court granted writs of certiorari and will review the question of whether the Section 316(b) rules authorize the EPA to compare costs with benefits in determining the best technology available for minimizing "adverse environmental impact" at cooling water intake structures. It is not clear what changes, if any, the EPA will ultimately make to the Section 316(b) rules or how those changes may affect OG&E. Depending on the ultimate analysis and final determinations regarding the Section 316(b) rules and the comprehensive demonstration studies, capital and/or operating costs may increase at any affected OG&E generating facility. OG&E expects a ruling from the U.S. Supreme Court on the Section 316(b) rules in mid-2009.

#### **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 16 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.

## 16. 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, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the Department of Energy has jurisdiction over some of OG&E's facilities and operations. For the year ended December 31, 2008, approximately 88 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, nine 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

#### Acquisition of Redbud Power Plant

On January 21, 2008, OG&E entered into a Purchase and Sale Agreement ("Purchase and Sale Agreement") with Redbud Energy I, LLC, Redbud Energy II, LLC and Redbud Energy III, LLC ("Redbud Sellers"), which were indirectly owned by Kelson Holdings LLC, a subsidiary of Harbinger Capital Partners Master Fund I, Ltd. and Harbinger Capital Partners Special Situations Fund, L.P. Pursuant to the Purchase and Sale Agreement, OG&E agreed to acquire from the Redbud Sellers the entire partnership interest in Redbud Energy LP which owned the Redbud Facility for approximately \$852 million, subject to working capital and inventory adjustments in accordance with the terms of the Purchase and Sale Agreement.

In connection with the Purchase and Sale Agreement, OG&E also entered into (i) an Asset Purchase Agreement ("Asset Purchase Agreement") with the OMPA and the GRDA, pursuant to which OG&E agreed that it would, after the closing of the transaction contemplated by the Purchase and Sale Agreement, dissolve Redbud Energy LP and sell a 13 percent undivided interest in the Redbud Facility to the OMPA and sell a 36 percent undivided interest in the Redbud Facility to the GRDA, and (ii) an Ownership and Operating Agreement ("Ownership and Operating Agreement") with the OMPA and the GRDA, pursuant to which OG&E, the OMPA and the GRDA, following the completion of the transaction contemplated by the Asset Purchase Agreement, would jointly own the Redbud Facility and OG&E will act as the operations manager and perform the day-to-day operation and maintenance of the Redbud Facility. Under the Ownership and Operating Agreement, each of the parties would be entitled to its pro rata share, which is equal to

its respective ownership interest, of all output of the Redbud Facility and would pay its pro rata share of all costs of operating and maintaining the Redbud Facility, including its pro rata share of the operations manager's general and administrative overhead allocated to the Redbud Facility.

The transactions described above were subject to an order from the FERC authorizing the contemplated transactions and an order from the OCC approving the prudence of the transactions and an appropriate reasonable recovery mechanism, and other customary conditions.

On September 16, 2008, the FERC issued an order approving the Redbud acquisition. In the order, the FERC concluded that the Redbud acquisition could harm horizontal competition by increasing market concentration. However, the FERC concluded that, since OG&E had committed to construct specific upgrades on the system, these would be adequate mitigation measures. Accordingly, the FERC conditioned its approval of the Redbud acquisition on OG&E's completion of these upgrades. OG&E is required to file quarterly updates describing the progress of the transmission upgrades, the first of which was filed December 16, 2008. OG&E also must notify the FERC of any change in circumstances regarding these projects. During the approximately 27-month period required to construct the transmission upgrades, the FERC did not require any interim mitigation beyond the limits of OG&E's market-based rate authority and the SPP market monitoring programs currently in place. In addition, the FERC found that the proposed transaction would have no adverse effects on vertical market power, on wholesale rates, or on state or Federal regulation. The FERC also determined that the transaction presented no cross-subsidy concerns. Finally, the FERC rejected various arguments raised by AES that sought to expand the scope of the FERC proceeding or to impose additional conditions on the Redbud acquisition. On September 24, 2008, the OCC issued an order approving the Redbud acquisition. OG&E closed on the Redbud acquisition on September 29, 2008. OG&E implemented a rider at the end of September 2008 to recover the Oklahoma jurisdiction revenue requirement until new rates are implemented that include Redbud's net investment, operation and maintenance expense, depreciation expense and ad valorem taxes.

#### Cancelled Red Rock Power Plant and Storm Cost Recovery Rider

On October 11, 2007, the OCC issued an order denying OG&E and Public Service Company of Oklahoma's ("PSO") request for pre-approval of their proposed 950 MW Red Rock coal-fired power plant project. The plant, which was to be built at OG&E's Sooner plant site, was to be 42 percent owned by OG&E, 50 percent owned by PSO and eight percent owned by the OMPA. As a result, on October 11, 2007, OG&E, PSO and the OMPA agreed to terminate agreements to build and operate the plant. At December 31, 2007, OG&E had incurred approximately \$17.5 million of capitalized costs associated with the Red Rock power plant project. In December 2007, OG&E filed an application with the OCC requesting authorization to defer, and establish a method of recovery of, approximately \$14.7 million of Oklahoma jurisdictional costs associated with the Red Rock power plant project. Specifically, OG&E requested authorization to sell approximately \$14.7 million of its SO<sub>2</sub> allowances and to retain 100 percent of the proceeds to offset the \$14.7 million of Red Rock costs. Under a prior order of the OCC, 90 percent of the

proceeds from sales of SO2 allowances were to be credited to ratepayers. Any portion of the \$14.7 million of deferred costs that the OCC did not approve for recovery by OG&E was to be expensed. In its response to OG&E's Red Rock cost recovery application, the OCC Staff recommended, among other things, that OG&E sell SO2 allowances and retain 100 percent of the proceeds from the sale to be used to offset OG&E's December 2007 ice storm costs. These ice storm costs were included as part of the regulatory asset balance of approximately \$35.9 million at December 31, 2007 (see Note 1), in accordance with a prior order of the OCC, pending recovery in a future rate case. On June 27, 2008, OG&E filed an application requesting a Storm Cost Recovery Rider ("SCR") for the years 2007 through 2009 to recover excess storm damage costs and, at the same time, filed a motion to consolidate for hearing the Red Rock application and the SCR application. On July 24, 2008, a settlement agreement was signed by all the parties involved in the two cases. Under the terms of the settlement agreement, OG&E will: (i) recover approximately \$7.2 million, or 50 percent, of the Oklahoma jurisdictional portion of the Red Rock power plant deferred costs through a regulatory asset, (ii) amortize the Red Rock regulatory asset over a 27-year amortization period and earn the OCC's authorized rate of return beginning with OG&E's next rate case, (iii) accrue carrying costs on the debt portion of the Red Rock regulatory asset from October 1, 2007 until the date OG&E begins to recover the regulatory asset through the base rates established in OG&E's next rate case, (iv) recover the OCC Staff and Attorney General consulting fees of approximately \$0.3 million related to the Red Rock pre-approval case, in OG&E's next rate case by amortizing this over a two-year period, (v) recover approximately \$33.7 million of the 2007 storm costs regulatory asset, which resulted in a write-down of approximately \$1.5 million, (vi) implement the SCR to recover OG&E's actual storm expense for the four-year period from 2006 through 2009, (vii) retain the first \$3.4 million from the sale of excess SO2 allowances, (viii) reduce storm costs recovered through the SCR by the proceeds from the sale of SO2 allowances above the amount retained by OG&E and (ix) earn the most recent OCC authorized return on the unrecovered storm cost balance through the SCR. On August 22, 2008, the OCC issued an order approving the settlement agreement and the SCR was implemented in September 2008. In June 2008, OG&E wrote down the Red Rock deferred cost and the storm costs to their net present value, which resulted in a pre-tax charge of approximately \$9.0 million, which is currently included in Deferred Charges and Other Assets with an offset in Other Expense on the Company's Consolidated Financial Statements.

#### Renewable Energy Filing

OG&E announced in October 2007 its goal to increase its wind power generation over the next four years from its 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. OG&E intends to add the new capacity to its power-generation portfolio no later than the end of 2010.

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 at a cost of approximately \$211 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 2010. Finally, the application requested the OCC to approve new renewable tariff offerings to OG&E's Oklahoma customers. On July 11, 2008, the OCC Staff filed responsive testimony recommending approval of OG&E's renewable plan and the Oklahoma Industrial Energy Consumers opposed OG&E's request. 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 the Company will: (i) receive pre-approval for construction of a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma 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 a subsequent 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. 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 Extra High Voltage substation.

#### Review of OG&E's Fuel Adjustment Clause for Calendar Year 2006

The OCC routinely audits activity in OG&E's fuel adjustment clause for each calendar year. In September 2007, the OCC Staff filed an application for a prudence review of OG&E's 2006 fuel adjustment clause. In September 2008, the OCC issued an order approving the fuel, purchased power and purchase gas adjustment clause cost recoveries for calendar year 2006.

#### Pending Regulatory Matters

##### OG&E FERC Formula Rate Filing

On November 30, 2007, OG&E made a filing at the FERC to increase its transmission rates to wholesale customers moving electricity on OG&E's transmission lines. Interventions and protests were due by December 21, 2007. While several parties filed motions to intervene in the docket, only the OMPA filed a protest to the contents of OG&E's filing. OG&E filed an answer to the OMPA's protest on January 7, 2008. On January 31, 2008, the FERC issued an order (i) conditionally accepting the rates; (ii) suspending the effectiveness of such rates for five months, to be effective July 1, 2008, subject to refund; (iii) establishing hearing and settlement judge procedures; and (iv) directing OG&E to make a compliance filing. In July 2008, rates were implemented in an annual amount of approximately \$2.4 million, subject to refund. Several settlement conferences have been held with the most recent being on November 17 and 18, 2008. Since the November 17 and 18, 2008 settlement conferences, the parties have continued to engage in settlement discussions.

#### OG&E Arkansas Rate Case Filing

On August 29, 2008, OG&E filed with the APSC an application for an annual rate increase of approximately \$26.4 million to recover, among other things, costs for investments including the Redbud Facility and improvements in its system of power lines, substations and related equipment to ensure that OG&E can reliably meet growing customer demand for electricity, and a return on equity of 12.25 percent. In January 2009, the APSC Staff recommended a \$12.0 million rate increase based on a 10.5 percent return on equity. The Attorney General's consultant recommended a return on equity at the current authorized level of 10.0 percent and stated that his analysis identified at least \$10.9 million in reductions to OG&E's rate increase request. A hearing is scheduled for April 7, 2009. An order from the APSC is expected in June 2009 with new rates targeted for implementation in July 2009.

#### OG&E 2008 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 requests the APSC to provide for recovery of the deferred 2008 storm costs in OG&E's pending rate case. On December 19, 2008, the APSC issued an order authorizing OG&E to defer approximately \$0.6 million in 2008 for incremental storm costs in excess of the amount included in OG&E's rates. OG&E was also authorized to seek recovery in its pending rate case but was not guaranteed recovery. At December 31, 2008, these incremental storm costs were approximately \$0.6 million, which has been recorded as a regulatory asset (see Note 1).

#### OG&E 2009 Oklahoma Rate Case Filing

Beginning in October 2008, OG&E began developing a rate case filing for the Oklahoma jurisdiction. On January 20, 2009, OG&E notified the OCC that it will make its planned Oklahoma rate case filing on or about February 26, 2009. OG&E is finalizing the preparation of the rate case and expects to request an increase of between \$100 million and \$110 million. The case is expected to proceed through the first half of 2009. If an increase is approved by the OCC, electric rates would likely be implemented in September 2009 at the earliest.

#### OG&E System Hardening Filing

In December 2007, a major ice storm affected OG&E's service territory which resulted in a large number of customer outages. The OCC requested its Staff to review and determine if a rulemaking was warranted. The OCC Staff issued numerous data requests and is in the process of determining if other regulatory jurisdictions have policies or rules requiring that electric transmission and distribution lines be placed underground. The OCC Staff also surveyed customers. On June 30, 2008, the OCC Staff submitted a report entitled, "Inquiry into Undergrounding Electric Facilities in the State of Oklahoma." OG&E formed a plan to place facilities underground (sometimes referred to as system hardening) with capital expenditures of approximately \$115 million over five years for underground facilities, as well as \$10 million annually for enhanced vegetation management. On December 2, 2008, OG&E filed an application with the OCC requesting approval of its proposed system hardening plan with a recovery rider. On February 5, 2009,

a procedural schedule was set in this matter with a hearing scheduled for March 25, 2009. The Company expects to receive an order from the OCC in the second quarter of 2009, with a targeted implementation date for the program and rider in the third quarter of 2009.

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

The OCC routinely audits activity in OG&E's fuel adjustment clause for each calendar year. In September 2008, the OCC Staff filed an application for a prudence review of OG&E's 2007 fuel adjustment clause. OG&E is required to provide minimum filing requirements ("MFR") within 60 days of the application; however, OG&E requested and was granted an extension to file the MFRs by January 16, 2009, on which date the MFRs were submitted by OG&E. A procedural schedule has not been established in this matter.

#### Security Enhancements

On January 15, 2009, OG&E filed an application with the OCC to amend its security plan. OG&E is seeking approval of new security projects and cost recovery through the previously authorized security rider. The annual revenue requirement is approximately \$0.9 million. OG&E expects to receive an order from the OCC in the third quarter of 2009. A procedural schedule has not been established in this matter.

#### Southwest Power Pool Transmission/Substation Project

In January 2009, OG&E received notification from the SPP to begin construction on approximately 50 miles of new 345kV transmission line and certain substation upgrades at OG&E's Sunnyside substation, among other projects. The line will extend from OG&E's Sunnyside substation near Ardmore, Oklahoma, to a point approximately one-half of the distance to the Hugo substation owned by the Western Farmers Electric Cooperative near Hugo, Oklahoma. The line and substation improvements are estimated to cost approximately \$96 million. OG&E intends to begin preliminary line routing and acquisition of rights-of-way in early 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.

#### OGE Energy and Electric Transmission America Joint Venture

In July 2008, OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture to construct high-capacity transmission line projects in western Oklahoma. The Company will own 50 percent of the joint venture. The joint venture is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. Work on the joint venture projects is scheduled to begin in late 2009 and is targeted for completion by the end of 2013. The joint venture projects are subject to creation by the SPP of a cost allocation method that would spread the total cost across the SPP region. The project also required approval from the FERC. OGE Energy filed an application with the FERC in October 2008 for cost recovery of these projects subject to SPP and FERC approval for these projects. On

December 2, 2008, the FERC granted the joint venture's request for transmission rate incentives for the initial projects, established a base return on equity for initial projects, approved certain accounting treatments for the initial projects and set the formula rate and accompanying protocols for hearing and settlement discussions. The joint venture's initial projects will include 765 kilovolt lines from Woodward 120 miles northwest to Guymon in the Oklahoma Panhandle and from Woodward 50 miles north to the Kansas border. An SPP study estimates cost for the two projects to be approximately \$500 million, of which OGE Energy's portion will be approximately \$250 million.

#### Enogex 2009 Fuel Filing

As required by the fuel tracker provisions of its Statement of Operating Conditions, Enogex files annually to update its fuel percentages. In the settlement of its 2004 Section 311 rate case, Enogex agreed to move from a systemwide fuel percentage to zonal fuel percentages. Accordingly, in all of the annual fuel filings made subsequent to the FERC's acceptance of the 2004 rate case settlement, Enogex has filed for fixed fuel percentages for the East Zone and the West Zone, respectively. On November 21, 2008, Enogex made its annual filing to establish the fixed fuel percentages for its East Zone and West Zone for calendar year 2009 ("2009 Fuel Year"). The FERC accepted the proposed zonal fuel percentages for the 2009 Fuel Year by an order dated January 8, 2009.

#### 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 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.

The regulations provide that the FERC has 150 days to act on the filing but also permit the FERC to issue an order extending the time period for action. By order of February 28, 2008, the FERC extended the time period in this docket by 120 days and encouraged the parties to settle. No action has yet been taken by the FERC and the parties are currently in settlement negotiations.

On November 13, 2007, one of the protesting intervenors filed to consolidate the Enogex 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. Additional pleadings were also filed by this intervenor after the initial protest and Enogex and MEP separately opposed this intervenor's assertions. By order dated July 25, 2008, the FERC approved the MEP project and denied the intervenors' request for consolidation of the MEP proceedings with the Enogex rate case. The intervenor has filed a request for rehearing in the MEP project and lease proceedings. The FERC has not yet acted on the request. Enogex has not, as of yet, placed the increased rates into effect while settlement negotiations continue. Enogex has a regulatory obligation to file its next rate case no later than October 1, 2010 to comply with the FERC's requirement for triennial filings, but plans to file a new rate case during the first half of 2009. While Enogex has yet to finalize various compo-

nents of the new filing, Enogex is finalizing agreements with East Zone shippers interested in firm Section 311 service on the East Zone of its system and anticipates offering in the near-term a limited firm Section 311 service on the East Zone for the first time.

#### Market-Based Rate Authority

On December 22, 2003, OG&E and OERI filed a triennial market power update 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 the new interim tests. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 that applied the interim tests to OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but did not pass the market share screen in OG&E's control area. OG&E and OERI provided an explanation as to why their failure of the market share screen in OG&E's control area should not be viewed as an indication that they can exercise generation market power.

On June 7, 2005, the FERC issued an order on OG&E's and OERI's market-based rate filing. Because OG&E and OERI failed the market share screen for OG&E's control area, the FERC established hearing procedures to investigate whether OG&E and OERI may continue to sell power at market-based rates in OG&E's control area. The order established a rebuttable presumption that OG&E and OERI have the ability to exercise market power in OG&E's control area. OG&E and OERI were requested to provide additional information that demonstrates to the FERC that they cannot exercise market power in the first-tier markets as well. However, the order conditionally allows OG&E and OERI to sell power in first-tier markets subject to OG&E and OERI providing additional information that clearly shows that they pass the market share screen for the first-tier markets. OG&E and OERI provided that additional information on July 7, 2005. On August 8, 2005, OG&E and OERI informed the FERC that they will: (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 will be filed with the FERC and that OG&E and OERI will not make such sales under their respective market-based rate tariffs. On January 20, 2006, the FERC issued a Notice of Institution of Proceeding and Refund Effective Date for the purpose of establishing the date from which any subsequent market-based sales would be subject to refund in the event the FERC concludes after investigation that the rates for such sales are not just and reasonable. The refund effective date was March 27, 2006.

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 the Company 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). On April 20, 2006, OG&E submitted: (i) a compliance filing containing the specified revisions to OG&E's market-based rate tariffs and the new cost-based rate tariff; and (ii) a request for rehearing asking the FERC to reconsider its expanded mitigation directive contained in the March 21, 2006 order. On May 22, 2006, the FERC issued a tolling order that effectively provided the FERC additional time to consider the April 20, 2006 rehearing request. On July 25, 2006 and August 25, 2006, pursuant to a FERC March 20, 2006 order, OG&E and OERI filed revisions to their market-based rate tariffs to allow them to sell energy imbalance service into the wholesale markets administered by the SPP at market-based rates. On April 4, 2008, the FERC rejected OG&E's April 20, 2006 request for rehearing and approved in part and rejected in part OG&E's April 20, 2006 compliance filing. The April 4, 2008 order directed OG&E to evaluate whether any refunds are required to comply with the April 4, 2008 order and to: (i) make any necessary refunds, or (ii) file a report with the FERC stating that no refunds are due. Refunds would apply only to new market-based sales made or new market-based contracts entered into after the March 21, 2006 order. The April 4, 2008 order also directed OG&E to make another compliance filing to revise its market-based rate tariffs to adhere to the FERC's June 21, 2007 final rule that revised standards for market-based rate sales of electric energy, capacity and ancillary services. On May 5, 2008, OG&E submitted a compliance report stating that no refunds were due. On May 30, 2008, OG&E and OERI submitted to the FERC a change in status report notifying the FERC that OG&E had entered into a contract with Westar Energy under which OG&E agreed to purchase 300 MWs of capacity and energy for the periods from May 1, 2008 through August 31, 2008, and from May 1, 2009 through August 31, 2009. OG&E and OERI explained that this purchase agreement was not material to the FERC's grant of market-based rate status to OG&E and OERI. The FERC has not yet acted on OG&E and OERI's May 30, 2008 change of status filing. On October 27, 2008, OG&E and OERI submitted to the FERC another change of status filing notifying FERC that OG&E had acquired a 51 percent interest in the Redbud Facility in Oklahoma, which increases the size of its generation resources by 610 MW. This filing indicated that: (i) OG&E's acquisition of the Redbud Facility does not reflect a material departure from the characteristics relied upon in granting OG&E/OERI market-based rate authority; (ii) OG&E/OERI continue to lack generation market power in first-tier markets; and (iii) OG&E's acquisition of the Redbud Facility does not effect OG&E's or OERI's previous analysis on transmission market power, affiliate abuse or barriers to entry. The FERC has not yet acted on OG&E's and OERI's October 27, 2008 change of status filing.

#### North American Electric Reliability Council

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 Council ("NERC") as the Electric Reliability Organization for North America and delegated to it the development and enforcement of electric transmis-

sion reliability rules. On April 19, 2007, the FERC approved the SPP as a Regional Entity whose primary function is to review and enforce compliance of reliability standards with all registered entities in the region. In March 2007, the FERC approved mandatory NERC reliability standards which became effective June 18, 2007. In November 2008, OG&E completed its periodic NERC compliance audit. Resolution of any audit findings is expected in 2009; however, OG&E does not expect the resolution of any audit findings to have a material impact on its operations. The Company is subject to a NERC readiness evaluation and compliance audit every three years. The next readiness evaluation is scheduled for 2010 and the next compliance audit is scheduled for 2011.

#### National Legislative Initiatives

In October 2008, Congress enacted and the President signed into law the Emergency Economic Stabilization Act of 2008 which contains, among other things, provisions designed to provide programs to: (i) address the nation's credit liquidity problems; (ii) provide disaster relief for adversely affected communities; (iii) preserve the value of homes, retirement accounts and promote job creation; and (iv) implement a wide range of tax provisions, including several of particular interest to the investor-owned utility sector. Among the tax provisions benefiting the utility sector are the extension of tax credits for renewable energy production, carbon mitigation and clean coal technology, plug-in hybrid vehicles, increasing residential and commercial building energy efficiency, energy efficient appliances and accelerated depreciation for smart meters and smart grid systems. Of particular interest to the Company is the extension through 2009 of the renewable energy production tax credit that was scheduled to expire at the end of 2008, which plays a prominent role regarding the financing and economics of wind energy projects.

In December 2008, Congress enacted and the President signed into law legislation providing some relief for companies regarding mandatory pension payment obligations that had become complicated by the economic downturn. This legislation allowed companies greater latitude in meeting their pension obligations through temporary adjustments regarding mandatory minimum distributions and plan funding targets. The utility and natural gas midstream industries supported this legislation and is seeking broader temporary adjustments for pension plan funding in 2009.

#### State Legislative Initiatives

House Bill 2813 ("HB 2813") was signed into law in May 2008, at which time it became effective. HB 2813 was created in order to advance the development of Oklahoma's vast wind power potential. This law provides for additional financial certainty for transmission line projects deemed necessary for the development of wind energy. The costs associated with such transmission lines are to be presumed to be recoverable if the lines are in service within five years of the passage of the law and meet the necessary criteria. OG&E has announced its intentions to build transmission lines and substantially increase the amount of generation it produces by wind, and management believes that this legislation increases the likelihood of recovering the costs associated with the construction of transmission lines.

House Bill 1739 (“HB 1739”) was signed into law in May 2008, with an effective date of January 1, 2009. HB 1739 creates a system whereby utilities can divide their territories with the proper government oversight. The bill only relates to new customers in the territory and does not allow switching of existing customers. The law also codifies the right of investor-owned utilities to be able to continue serving in annexed territories of cities with municipal electric systems, where they can demonstrate a prior right to be in the annexed territory. The law is retroactive to include previous annexations as well as those that may occur in the future. This law also clarifies which utilities can serve in a territory annexed by a city because duplication of infrastructure has caused problems over the years since it possesses a potential safety hazard to line workers. The benefits of this law to OG&E include being able to reduce future duplication of power lines and other infrastructure as well as clearly establishing the right to serve in areas previously considered legally questionable by certain parties.

Legislation was enacted in Oklahoma in the 1990’s that was to restructure the electric utility industry in that state. The implementation of the Oklahoma restructuring legislation was delayed and seems unlikely

to proceed anytime in the near future. Yet, if ultimately enacted, this legislation could deregulate OG&E’s electric generation assets and cause OG&E to discontinue the use of SFAS No. 71 with respect to its related regulatory balances. The previously-enacted Oklahoma legislation would not affect OG&E’s electric transmission and distribution assets and OG&E believes that the continued use of SFAS No. 71 with respect to the related regulatory balances is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management believes that its regulatory assets, including those related to generation, are probable of future recovery.

#### Summary

The Energy Policy Act of 2005, the actions of the FERC, the restructuring legislation in Oklahoma 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, 2008 and 2007, 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, 2008. 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, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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 11, 2009 expressed an unqualified opinion thereon.

As discussed in Notes 6 and 9 to the consolidated financial statements, in 2007 the Company adopted Financial Accounting Standards Board Interpretation No. 48, “Accounting for Uncertainty in Income Taxes,” and Financial Accounting Standards Board Interpretation No. 39 (As Amended), “Offsetting of Amounts Related to Certain Contracts.”



**Ernst & Young LLP**

Oklahoma City, Oklahoma  
February 11, 2009

## 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
<b>Operating revenues</b>					
2008	\$994.7	\$1,135.7	\$1,254.3	\$686.0	\$4,070.7
2007	881.5	913.4	1,044.5	958.2	3,797.6
<b>Operating income</b>					
2008	\$ 48.1	\$ 122.7	\$ 231.2	\$ 60.1	\$ 462.1
2007	46.2	117.2	218.3	73.6	455.3
<b>Net income</b>					
2008	\$ 13.0	\$ 57.1	\$ 139.5	\$ 21.8	\$ 231.4
2007	17.2	62.6	126.8	37.6	244.2
<b>Basic earnings per average common share</b>					
2008	\$ 0.14	\$ 0.62	\$ 1.51	\$ 0.23	\$ 2.50
2007	0.19	0.68	1.38	0.41	2.66
<b>Diluted earnings per average common share</b>					
2008	\$ 0.14	\$ 0.62	\$ 1.50	\$ 0.23	\$ 2.49
2007	0.19	0.68	1.37	0.40	2.64

### Dividends

#### Common Stock

- 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. Common quarterly dividends paid (as declared) in 2006 were \$0.3325 each for the first three quarters of 2006 and was \$0.34 for the fourth quarter of 2006.
- Present rate – \$0.3550
- Payable 30th of January, April, July, and October

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

	Dividend Paid	High	Low
<b>2009</b>			
First quarter (through January 31)	\$0.3550	\$26.80	\$23.56
<b>2008</b>			
First quarter	\$0.3475	\$36.23	\$29.83
Second quarter	0.3475	34.02	30.61
Third quarter	0.3475	34.74	29.67
Fourth quarter	0.3475	31.41	19.56
<b>2007</b>			
First quarter	\$0.3400	\$41.30	\$36.39
Second quarter	0.3400	39.65	33.65
Third quarter	0.3400	37.59	29.12
Fourth quarter	0.3400	38.30	32.93

### Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

### 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, 2008. 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, 2008, 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 below.



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



**Scott Forbes**  
Controller, Chief Accounting Officer  
and Interim Chief Financial Officer



**Danny P. Harris**  
Senior Vice President  
and Chief Operating 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, 2008, 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 our 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, 2008, 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, 2008 and 2007, 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, 2008 of OGE Energy Corp. and our report dated February 11, 2009 expressed an unqualified opinion thereon.



**Ernst & Young LLP**  
Oklahoma City, Oklahoma  
February 11, 2009

## Historical Performance

(In millions except per share data)	2008	2007	2006 <sup>(A)</sup>	2005 <sup>(B)</sup>	2004 <sup>(B)</sup>
<b>Selected Financial Data</b>					
Operating revenues	\$ 4,070.7	\$ 3,797.6	\$ 4,005.6	\$ 5,911.5	\$ 4,862.6
Cost of goods sold	2,818.0	2,634.7	2,902.5	4,942.3	3,937.7
Gross margin on revenues	1,252.7	1,162.9	1,103.1	969.2	924.9
Other operating expenses	790.6	707.6	670.4	646.8	630.4
Operating income	462.1	455.3	432.7	322.4	294.5
Interest income	6.7	2.1	6.2	3.5	4.9
Allowance for equity funds used during construction	–	–	4.1	–	0.9
Other income (loss)	15.4	17.4	16.3	(0.3)	10.5
Other expense	31.6	23.7	16.7	5.5	4.7
Interest expense	120.0	90.2	96.0	90.3	90.8
Income tax expense	101.2	116.7	120.5	68.6	73.4
Income from continuing operations	231.4	244.2	226.1	161.2	141.9
Income from discontinued operations, net of tax	–	–	36.0	49.8	11.6
Net income	\$ 231.4	\$ 244.2	\$ 262.1	\$ 211.0	\$ 153.5
Diluted earnings (loss) per average common share					
Income from continuing operations	\$ 2.49	\$ 2.64	\$ 2.45	\$ 1.77	\$ 1.60
Income from discontinued operations, net of tax	\$ –	\$ –	\$ 0.39	\$ 0.55	\$ 0.13
Income per average common share	\$ 2.49	\$ 2.64	\$ 2.84	\$ 2.32	\$ 1.73
Long-term debt	\$ 2,161.8	\$ 1,344.6	\$ 1,346.3	\$ 1,350.8	\$ 1,424.1
Total assets <sup>(C)</sup>	\$ 6,518.5	\$ 5,237.8	\$ 4,898.4	\$ 4,871.4	\$ 4,787.1
<b>Common Stock Statistics</b>					
Dividends paid per share	\$ 1.39	\$ 1.36	\$ 1.33	\$ 1.33	\$ 1.33
Dividends declared per share	\$ 1.3975	\$ 1.3675	\$ 1.3375	\$ 1.33	\$ 1.33
Book value	\$ 20.28	\$ 18.31	\$ 17.56	\$ 15.19	\$ 14.29
Market price – year end	\$ 25.78	\$ 36.29	\$ 40.00	\$ 26.79	\$ 26.51
Price/earnings ratio – year end	10.3	13.6	13.9	11.4	15.2
Basic average shares outstanding (millions)	92.4	91.7	91.0	90.3	88.0
Diluted average shares outstanding (millions)	92.8	92.5	92.1	90.8	88.5
Actual shares outstanding (millions)	93.5	91.8	91.2	90.6	90.0
Number of shareowners	22,705	23,983	25,198	26,369	30,961
<b>Capitalization Ratios<sup>(D)</sup></b>					
Common equity	46.7%	55.5%	54.3%	50.5%	46.9%
Long-term debt	53.3%	44.5%	45.7%	49.5%	53.1%
<b>Miscellaneous Statistics</b>					
Electric customers	770,088	762,234	754,840	745,493	735,008
Mwh sales (millions)	28.2	27.1	26.4	26.1	24.8
Mw generating capability – year end (thousands)	6.8	6.2	6.1	6.1	6.1
Mw peak demand (thousands)	6.5	6.3	6.5	6.1	5.8
Fuel mix (generation only, by kwh generated)					
Natural gas	30%	36%	33%	30%	30%
Coal	68%	62%	67%	70%	70%
Wind	2%	2%	–%	–%	–%
Cost (per million Btu)					
Natural gas	\$ 8.40	\$ 6.77	\$ 7.10	\$ 8.76	\$ 6.57
Coal	\$ 1.11	\$ 1.10	\$ 1.10	\$ 0.98	\$ 1.00
Weighted average	\$ 3.30	\$ 3.13	\$ 2.98	\$ 3.21	\$ 2.69
New gas well connects (includes wells behind central receipt points) <sup>(E)</sup>	357	374	362	–	–
New gas well connects (excludes wells behind central receipt points)	203	178	206	223	192
Total gas throughput volumes (trillion Btu/day)	1.57	1.52	1.44	1.31	1.23
Total natural gas processed (trillion Btu/day)	0.66	0.57	0.54	0.52	0.50
Total natural gas liquids sold (million gallons)	426	385	371	302	279
Average sales price per gallon	\$ 1.255	\$ 1.048	\$ 0.902	\$ 0.873	\$ 0.720

(A) The Company adopted SFAS No. 123 (Revised), "Share-Based Payment," using the modified prospective transition method, effective January 1, 2006, which required the Company to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award.

(B) Amounts for 2005 and 2004 were restated for discontinued operations related to the sale of Enogex assets in May 2006.

(C) Amounts for years 2004 through 2006 have been restated to net price risk management assets and liabilities under master netting agreements in accordance with FASB Interpretation No. 39.

(D) Capitalization ratios =  $\frac{\text{Stockholders' equity}}{\text{Stockholders' equity} + \text{Long-term debt} + \text{Long-term debt due within one year}}$  and  $\frac{\text{Long-term debt}}{\text{Long-term debt} + \text{Long-term debt due within one year}}$ .

(E) Includes wells behind central receipt points (as reported to us by third parties). This information is not available for years prior to 2006 as the Company's books and records were not maintained in a manner to provide this information for years prior to 2006.

## Investor Information

### Annual Meeting

The annual meeting of shareowners is scheduled for 10 a.m. Thursday, May 21, 2009, 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, 2009.

### 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:

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](http://www.bnymellon.com/shareowner/isd)  
or [www.oge.com](http://www.oge.com)

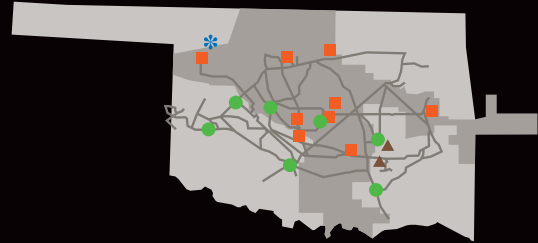
### Additional Information

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



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 2008, our company's employees pledged more than \$745,000 to United Way campaigns in communities where they live and work.



■ OGE service area    \* Wind power facilities    ● Natural gas processing  
~ Enogex pipeline    ■ Power plant    ▲ Natural gas storage

### 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](http://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.

### 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](http://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.

The Company filed the Section 302 Chief Executive Officer ("CEO") and Chief Financial Officer certifications as exhibits to its 2008 Form 10-K. The Company also filed the 2008 Section 303A.12(a) CEO certification to the New York Stock Exchange in June 2008.



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