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

# FORM 10-K

(Mark One)
S ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012

**OR**

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

Commission File Number: 1-12579

**OGE ENERGY CORP.**
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Oklahoma** | **73-1481638** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

**321 North Harvey**
**P.O. Box 321**
**Oklahoma City, Oklahoma 73101-0321**
(Address of principal executive offices)
(Zip Code)
Registrant's telephone number, including area code: **405-553-3000**

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

| Title of each class | Name of each exchange on which registered |
|---|---|
| Common Stock | New York Stock Exchange |

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. R Yes £ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). R Yes £ No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

| | |
|---|---|
| Large accelerated filer R | Accelerated filer £ |
| Non-accelerated filer £ (Do not check if a smaller reporting company) | Smaller reporting company £ |

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

At June 29, 2012, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of shares of common stock held by non-affiliates was $5,076,608,581 based on the number of shares held by non-affiliates (98,022,950) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $51.79.

At January 31, 2013, there were 98,790,726 shares of common stock, par value $0.01 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2013 annual meeting of shareowners is incorporated by reference into Part III of this Form 10-K.

**OGE ENERGY CORP.**

**FORM 10-K**

**FOR THE YEAR ENDED DECEMBER 31, 2012**

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## GLOSSARY OF TERMS

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

| Abbreviation | Definition |
|---|---|
| 401(k) Plan | Qualified defined contribution retirement plan |
| APSC | Arkansas Public Service Commission |
| ArcLight group | Bronco Midstream Holdings, LLC, Bronco Midstream Holdings II, LLC, collectively |
| Atoka | Atoka Midstream LLC joint venture |
| BART | Best available retrofit technology |
| Chesapeake | Chesapeake Energy Marketing, Inc. and Chesapeake Exploration L.L.C. |
| Code | Internal Revenue Code of 1986 |
| Company | OGE Energy, collectively with its subsidiaries |
| Cordillera | Cordillera Energy Partners III, LLC |
| Dodd-Frank Act | Dodd-Frank Wall Street Reform and Consumer Protection Act |
| Dry Scrubbers | Dry flue gas desulfurization units with spray dryer absorber |
| EBITDA | Enogex Holdings earnings before interest, taxes, depreciation and amortization |
| EER | Enogex Energy Resources LLC, wholly-owned subsidiary of Enogex LLC (prior to June 30, 2012, the legal name was OGE Energy Resources LLC) |
| Enogex | OGE Holdings, collectively with its subsidiaries |
| Enogex Holdings | Enogex Holdings LLC, the parent company of Enogex LLC and a majority-owned subsidiary of OGE Holdings |
| Enogex LLC | Enogex LLC, collectively with its subsidiaries |
| EPA | U.S. Environmental Protection Agency |
| Federal Clean Water Act | Federal Water Pollution Control Act of 1972, as amended |
| FERC | Federal Energy Regulatory Commission |
| FIP | Federal implementation plan |
| GAAP | Accounting principles generally accepted in the United States |
| MATS | Mercury and Air Toxics Standards |
| MEP | Midcontinent Express Pipeline, LLC |
| MMBtu | Million British thermal unit |
| MMcf/d | Million cubic feet per day |
| MW | Megawatt |
| MWH | Megawatt-hour |
| NAAQS | National Ambient Air Quality Standards |
| NGLs | Natural gas liquids |
| NOX | Nitrogen oxide |
| NYMEX | New York Mercantile Exchange |
| OCC | Oklahoma Corporation Commission |
| Off-system sales | Sales to other utilities and power marketers |
| OG&E | Oklahoma Gas and Electric Company |
| OGE Holdings | OGE Enogex Holdings, LLC, wholly-owned subsidiary of OGE Energy and parent company of Enogex Holdings |
| OSHA | Federal Occupational Safety and Health Act of 1970 |
| Oxbow | Oxbow Midstream, LLC |
| Pension Plan | Qualified defined benefit retirement plan |
| PHMSA | U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration |
| PRM | Price risk management |
| PSO | Public Service Company of Oklahoma |
| QF | Qualified cogeneration facilities |
| QF contracts | Contracts with QFs and small power production producers |
| Restoration of Retirement Income Plan | Supplemental retirement plan to the Pension Plan |
| SIP | State implementation plan |
| SO2 | Sulfur dioxide |
| SPP | Southwest Power Pool |
| System sales | Sales to OG&E's customers |
| TBtu/d | Trillion British thermal units per day |

## FORWARD-LOOKING STATEMENTS

Except for the historical statements contained herein, the matters discussed in this Form 10-K, including those matters discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential", "project" and similar expressions. Actual results may vary materially from those expressed in forward-looking statements. In addition to the specific risk factors discussed in "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" herein, factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- general economic conditions, including the availability of credit, access to existing lines of credit, access to the commercial paper markets, actions of rating agencies and their impact on capital expenditures;
- the ability of the Company and its subsidiaries to access the capital markets and obtain financing on favorable terms as well as inflation rates and monetary fluctuations;
- prices and availability of electricity, coal, natural gas and NGLs, each on a stand-alone basis and in relation to each other as well as the processing contract mix between percent-of-liquids, percent-of-proceeds, keep-whole and fixed-fee;
- business conditions in the energy and natural gas midstream industries;
- competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company;
- unusual weather;
- availability and prices of raw materials for current and future construction projects;
- Federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company's markets;
- environmental laws and regulations that may impact the Company's operations;
- changes in accounting standards, rules or guidelines;
- the discontinuance of accounting principles for certain types of rate-regulated activities;
- the cost of protecting assets against, or damage due to, terrorism or cyber attacks and other catastrophic events;
- advances in technology;
- creditworthiness of suppliers, customers and other contractual parties;
- the higher degree of risk associated with the Company's nonregulated business compared with the Company's regulated utility business; and
- other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission including those listed in "Item 1A. Risk Factors" and in Exhibit 99.01 to this Form 10-K.

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

# PART I

## Item 1. Business.

## THE COMPANY

### Introduction

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 three business segments: (i) electric utility, (ii) natural gas transportation and storage and (iii) natural gas gathering and processing. For financial information regarding these segments, see Note 15 of Notes to Consolidated Financial Statements. The Company was incorporated in August 1995 in the state of Oklahoma and its principal executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone 405-553-3000.

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

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. This new organization is intended to facilitate the execution of Enogex's strategy through an enhanced focus on asset optimization and active management of its growing natural gas, NGLs and condensate positions. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. Enogex's operations are now organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. At December 31, 2012, OGE Energy indirectly owns a 79.9 percent membership interest in Enogex Holdings, which in turn owns all of the membership interests in Enogex LLC.

### Company Strategy

The Company's mission is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customers' needs for energy and related services focusing on safety, efficiency, reliability, customer service and risk management. The Company's corporate strategy is to continue to maintain its existing business mix and diversified asset position of its regulated electric utility business and unregulated natural gas midstream business while providing competitive energy products and services to customers primarily in the south central United States as well as seeking growth opportunities in both businesses.

OG&E is focused on increased investment to preserve system reliability and meet load growth by adding and maintaining infrastructure equipment and replacing aging transmission and distribution systems. OG&E expects to maintain a diverse generation portfolio while remaining environmentally responsible. OG&E is focused on maintaining strong regulatory and legislative relationships for the long-term benefit of its customers. In an effort to encourage more efficient use of electricity, OG&E is also providing energy management solutions to its customers through the Smart Grid program that utilizes newer technology to improve operational and environmental performance as well as allow customers to monitor and manage their energy usage, which should help reduce demand during critical peak times, resulting in lower capacity requirements. If these initiatives are successful, OG&E believes it may be able to defer the construction or acquisition of any incremental fossil fuel generation capacity until 2020. The Smart Grid program also provides benefits to OG&E, including more efficient use of its resources and access to increased information about customer usage, which should enable OG&E to have better distribution system planning data, better response to customer usage questions and faster detection and restoration of system outages. As the Smart Grid platform matures, OG&E anticipates providing new products and services to its customers. In addition, OG&E is also pursuing additional transmission-related opportunities within the SPP.

Enogex's business plan entails growing its businesses and providing attractive financial returns through efficient operations and effective commercial management of its assets. Enogex also plans to capture growth opportunities through expansion projects, in creased utilization of existing assets and through acquisitions (including joint ventures) in and around its footprint and attracting new customers. In addition, Enogex is seeking to geographically diversify its gathering, processing and transportation businesses principally by expanding into other areas that are complementary with the Company's capabilities. Enogex expects to accomplish this diversification by undertaking organic growth projects and through acquisitions.

Additionally, the Company wants to achieve a premium valuation of its businesses relative to its peers, grow earnings per share with a stable earnings pattern, create a high performance culture and achieve desired outcomes with target stakeholders. The Company's financial objectives include a long-term annual earnings growth rate of five to seven percent on a weather-normalized basis, maintaining a strong credit rating as well as increasing the dividend to meet the Company's dividend payout objectives. The Company's target payout ratio is to pay out dividends no more than 60 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. The Company believes it can accomplish these financial objectives by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and maintaining strong regulatory and legislative relationships.

## ELECTRIC OPERATIONS - OG&E

### General

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E. OG&E furnishes retail electric service in 268 communities and their contiguous rural and suburban areas. During 2012, one other community and two rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from OG&E for resale. The service area covers 30,000 square miles in Oklahoma and western Arkansas, including Oklahoma City, the largest city in Oklahoma, and Fort Smith, Arkansas, the second largest city in that state. Of the 268 communities that OG&E serves, 242 are located in Oklahoma and 26 in Arkansas. OG&E derived 90 percent of its total electric operating revenues in 2012 from sales in Oklahoma and the remainder from sales in Arkansas.

OG&E's system control area peak demand in 2012 was 7,000 MWs on August 1, 2012. OG&E's load responsibility peak demand was 6,459 MWs on August 1, 2012. As reflected in the table below and in the operating statistics that follow, there were 28.0 million MWH system sales in 2012, 28.5 million MWH system sales in 2011 and 27.6 million MWH system sales in 2010. Variations in system sales for the three years are reflected in the following table:

| Year ended December 31 | **2012** | **2012 vs. 2011 Decrease** | 2011 | 2011 vs. 2010 Increase | 2010 |
|---|---|---|---|---|---|
| System sales - millions of MWHs | **28.0** | **(1.8)%** | 28.5 | 3.3% | 27.6 |

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

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

**OKLAHOMA GAS AND ELECTRIC COMPANY**
**CERTAIN OPERATING STATISTICS**

| Year ended December 31 | 2012 | 2011 | 2010 |
|---|---|---|---|
| ELECTRIC ENERGY *(Millions of MWH)* | | | |
| Generation (exclusive of station use) | **26.3** | 26.7 | 25.6 |
| Purchased | **5.0** | 4.9 | 4.7 |
| Total generated and purchased | **31.3** | 31.6 | 30.3 |
| OG&E use, free service and losses | **(1.9)** | (2.1) | (2.2) |
| Electric energy sold | **29.4** | 29.5 | 28.1 |
| ELECTRIC ENERGY SOLD *(Millions of MWH)* | | | |
| Residential | **9.1** | 9.9 | 9.6 |
| Commercial | **7.0** | 6.9 | 6.7 |
| Industrial | **4.0** | 3.9 | 3.8 |
| Oilfield | **3.3** | 3.2 | 3.1 |
| Public authorities and street light | **3.3** | 3.2 | 3.0 |
| Sales for resale | **1.3** | 1.4 | 1.4 |
| System sales | **28.0** | 28.5 | 27.6 |
| Off-system sales | **1.4** | 1.0 | 0.5 |
| Total sales | **29.4** | 29.5 | 28.1 |
| ELECTRIC OPERATING REVENUES *(In millions)* | | | |
| Residential | **$ 878.0** | $ 943.5 | $ 894.8 |
| Commercial | **523.5** | 531.3 | 521.0 |
| Industrial | **206.8** | 216.0 | 212.5 |
| Oilfield | **163.4** | 165.1 | 162.8 |
| Public authorities and street light | **202.4** | 207.4 | 200.8 |
| Sales for resale | **54.9** | 65.3 | 65.8 |
| System sales revenues | **2,029.0** | 2,128.6 | 2,057.7 |
| Off-system sales revenues | **36.5** | 36.2 | 21.7 |
| Other | **75.7** | 46.7 | 30.5 |
| Total operating revenues | **$ 2,141.2** | $ 2,211.5 | $ 2,109.9 |
| ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)* | | | |
| Residential | **683,214** | 675,806 | 670,309 |
| Commercial | **88,772** | 87,480 | 86,496 |
| Industrial | **2,957** | 2,991 | 3,020 |
| Oilfield | **6,426** | 6,451 | 6,418 |
| Public authorities and street light | **16,695** | 16,374 | 16,264 |
| Sales for resale | **46** | 44 | 51 |
| Total | **798,110** | 789,146 | 782,558 |
| AVERAGE RESIDENTIAL CUSTOMER SALES | | | |
| Average annual revenue | **$ 1,292.11** | $ 1,401.84 | $ 1,339.81 |
| Average annual use (kilowatt-hour) | **13,477** | 14,738 | 14,304 |
| Average price per kilowatt-hour (cents) | **$ 9.59** | $ 9.51 | $ 9.37 |

**Regulation and Rates**

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's wholesale electric tariffs, transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the U.S. Department of Energy has jurisdiction over some of OG&E's facilities and operations. In 2012, 87 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and five percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of OGE Energy. The order required that, among other things, (i) OGE Energy permit the OCC access to the books and records of OGE Energy and its affiliates relating to transactions with OG&E, (ii) OGE Energy employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) OGE Energy 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 OGE Energy and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates.

**Completed Regulatory Matters**

***OG&E Contract and Wind Energy Purchase Agreement Filing***

On December 1, 2011, OG&E filed an application with the OCC requesting approval of a 20-year agreement that is intended to provide wind power to help meet the current and future power generation needs of Oklahoma State University. The project called for OG&E to contract with NextEra Energy to build a 60 MW wind farm near Blackwell, Oklahoma, to support the Oklahoma State University project in which NextEra Energy built, owns and operates the wind farm and OG&E purchases the electric output. On February 22, 2012, OG&E, the Attorney General and the Public Utility Division of the OCC signed a settlement agreement whereby the stipulating parties requested that the OCC issue an order approving the agreement for electric service with Oklahoma State University. On March 12, 2012, OG&E received an order from the OCC approving the settlement agreement. Pursuant to the terms of the power purchase agreement between OG&E and NextEra Energy, OG&E has been purchasing the electric output of the wind farm since November 2012 and uses that power to provide service to Oklahoma State University and its other retail customers. The wind farm was fully in service in December 2012.

***OG&E SPP Transmission Projects***

The SPP is a regional transmission organization under the jurisdiction of the FERC that was created to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity. The SPP does not build transmission though the SPP's tariff contains rules that govern the transmission construction process. Transmission owners complete the construction and then own, operate and maintain transmission assets within the SPP region. When the SPP Board of Directors approves a project, the transmission provider in the area where the project is needed currently has the first obligation to build; however, the process for deciding which entity constructs and owns a project may change as a result of FERC Order. No. 1000 discussed below.

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

In 2007, the SPP notified OG&E to construct 44 miles of a new 345 kilovolt transmission line originating at OG&E's existing Sooner 345 kilovolt substation and proceeding generally in a northerly direction to the Oklahoma/Kansas Stateline (referred to as the Sooner-Rose Hill project). At the Oklahoma/Kansas Stateline, the line connects to the companion line constructed in Kansas by Westar Energy. The transmission line was placed in service in April 2012. The total capital expenditures associated with this project were $45 million.

In January 2009, OG&E received notification from the SPP to begin construction on 50 miles of a new 345 kilovolt transmission line and substation upgrades at OG&E's Sunnyside substation, among other projects. In April 2009, Western Farmers Electric Cooperative assigned to OG&E the construction of 50 miles of line designated by the SPP to be built by Western Farmers Electric Cooperative. The new line extends from OG&E's Sunnyside substation near Ardmore, Oklahoma, 123.5 miles to the

Hugo substation owned by Western Farmers Electric Cooperative near Hugo, Oklahoma. The transmission line was completed in April 2012. The total capital expenditures associated with this project were $157 million.

As discussed below, the OCC approved a settlement agreement in OG&E's 2011 Oklahoma rate case filing that included an expedited procedure for recovering the costs of the two projects. On July 31, 2012, OG&E filed an application with the OCC requesting an order authorizing recovery for the two projects through the SPP transmission systems additions rider. On October 2, 2012, all parties signed a settlement agreement in this matter which stated: (i) the parties agree not to oppose requested relief sought by OG&E, (ii) OG&E will host meetings to discuss the SPP’s transmission planning process, including any future transmission projects for which OG&E has received a notice to construct from the SPP, and (iii) there will be opportunities for parties to provide input related to transmission planning studies that the SPP performs to identify future transmission projects. On October 25, 2012, the OCC issued an order approving the settlement agreement and granting OG&E cost recovery for the two projects. OG&E initiated cost recovery beginning with the first billing cycle in November 2012.

***OG&E 2011 Oklahoma Rate Case Filing***

On July 28, 2011, OG&E filed its application with the OCC requesting an annual rate increase of $73.3 million, or a 4.3 percent increase in its rates. OG&E requested a return on equity of 11.0 percent based on a common equity percentage of 53.0 percent. In its application, OG&E requested recovery of increases in its operating costs and to begin earning on approximately $500 million of new capital investments made on behalf of its Oklahoma customers during the previous two and one-half years. On July 2, 2012, OG&E and other parties associated with its rate increase reached a settlement agreement in this matter. On July 9, 2012, the OCC issued an order approving the settlement agreement in this matter. Key terms of the settlement agreement included: (i) an annual net increase of approximately $4.3 million in OG&E's rates to its Oklahoma retail customers, (ii) OG&E's Oklahoma retail authorized return on equity of 10.2 percent, (iii) the rate of return under various recovery riders previously approved by the OCC, including riders for OG&E's smart grid implementation and Crossroads wind farm, is based on OG&E's actual debt and equity ratios as reflected in OG&E's application and a 10.2 percent return on equity, (iv) depreciation rates were implemented in the same month new customer rates went into effect, (v) the pension and postretirement medical cost tracker remains in effect, (vi) a procedure was established to expedite the recovery of the cost of specified high-voltage transmission projects and (vii) extension of funding for OG&E's system hardening program. OG&E expects the impact of the rate increase on its customers and service territory to be minimal as the rate increase will be more than offset by lower fuel costs attributable to prior fuel over recoveries from lower than forecasted fuel costs. OG&E implemented the new rates effective in early August.

***OG&E Smart Grid Project***

On December 17, 2010, OG&E filed an application with the APSC requesting pre-approval for system-wide deployment of smart grid technology and a recovery rider, including a credit for the Smart Grid grant awarded by the U.S. Department of Energy under the American Recovery and Reinvestment Act of 2009. On June 22, 2011, OG&E reached a settlement agreement with all the parties in this matter. OG&E and the other parties in this matter agreed to ask the APSC to approve the settlement agreement including the following: (i) pre-approval of system-wide deployment of smart grid technology in Arkansas and authorization for OG&E to begin recovering the prudently incurred costs of the Arkansas system-wide deployment of smart grid technology through a rider mechanism that will become effective in accordance with the order approving the settlement agreement; (ii) cost recovery through the rider would commence when all of the smart meters to be deployed in Arkansas are in service; (iii) OG&E guarantees that customers will receive certain operations and maintenance cost reductions resulting from the smart grid deployment as a credit to the recovery rider; and (iv) the stranded costs associated with OG&E's existing meters which are being replaced by smart meters will be accumulated in a regulatory asset and recovered in base rates beginning after an order is issued in OG&E's next general rate case. On August 3, 2011, the APSC issued an order in this matter approving the settlement agreement. On November 5, 2012, OG&E filed a revised smart grid recovery rider rate schedule. On December 13, 2012, the APSC issued an order in this matter approving the revised smart grid recovery rider to be effective beginning with the first billing cycle in January 2013 through December 2013. OG&E began recovering the estimated capital costs of $14 million and associated operation and maintenance costs for deployment of smart grid technology, along with incremental costs for web portal access and education of $0.8 million. The APSC also found that the prudence of OG&E’s smart grid expenditures will be determined in OG&E's next Arkansas rate case and that revenues collected under the rider are subject to refund, with interest, only in the event that the APSC determines that OG&E's smart grid expenditures were not prudent. The costs recoverable from Oklahoma customers for system-wide deployment of smart grid technology and implementing the smart grid pilot program were capped at $366.4 million (inclusive of the U.S. Department of Energy grant award amount) subject to an offset for any recovery of those costs from Arkansas customers and are currently being recovered through a rider which will remain in effect until the smart grid project costs are included in base rates in OG&E's next general rate case. This project was completed in late 2012 and the smart grid project costs did not exceed $366.4 million.

### *OG&E Demand and Energy Efficiency Program Filing*

On July 2, 2012, OG&E filed an application with the OCC requesting approval of OG&E's 2013 demand portfolio, the authorization to recover the program costs, lost revenues associated with any achieved energy, demand savings and performance based incentives through the demand program rider and the recovery of costs associated with research and development investments. On July 16, 2012, OG&E filed an amended application which modified various calculations to reflect the rate of return authorized by the OCC in OG&E's 2011 rate case order and provided for consideration of a peak time rebate program. On December 20, 2012, the OCC approved a settlement with all parties in this matter. Key terms of the settlement included (i) approval of the program budgets proposed by OG&E and an additional amount of approximately $7 million over the three-year period for the energy efficiency programs, (ii) approval of OG&E's proposed Demand Program Rider tariff, (iii) the recovery through the Demand Program Rider of the increased program costs and the net lost revenues, incentives and research and development investments requested by OG&E, with the exception of lost revenues resulting from the Integrated Volt Var Control program (automated intelligence to control voltage and power on the distribution lines) and incentives for the SmartHours® and Integrated Volt Var Control demand response programs, (iv) recovery of the program costs on a levelized basis over the three-year period, (v) consideration of implementing a peak time rebate program in 2015 and (vi) the periodic filing of additional reports. The Demand Program Rider became effective on January 1, 2013.

### *OG&E Fuel Adjustment Clause Review for Calendar Year 2010*

The OCC routinely reviews the costs recovered from customers through OG&E's fuel adjustment clause. On August 19, 2011, the OCC Staff filed an application to review OG&E's fuel adjustment clause for calendar year 2010, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. OG&E responded by filing direct testimony and the minimum filing review package on October 18, 2011. On September 26, 2012, the administrative law judge recommended that the OCC find that for the calendar year 2010 OG&E's generation, purchase power and fuel procurement processes and costs, including the cost of replacement power for the Sooner 2 outage, were prudent and no disallowance (as discussed below) for any of these expenses is warranted. On January 31, 2013, the OCC issued an order approving the administrative law judge's recommendation. Previously, the Oklahoma Industrial Energy Consumers recommended that the OCC disallow recovery of approximately $44 million of costs previously recovered through OG&E's fuel adjustment clause. These recommendations were based on allegations that OG&E's lower cost coal-fired generation was underutilized, that OG&E failed to aggressively pursue purchasing power at a cost lower than its marginal cost of generation and that OG&E should be found imprudent related to an unplanned outage at OG&E's Sooner 2 coal unit in November and December 2010. Previously, the OCC Staff recommended approval of OG&E's actions related to utilization of coal plants and practices related to purchasing power but recommended that OG&E refund $3 million to customers because of the Sooner 2 outage.

## Pending Regulatory Matters

### *FERC Order No. 1000, Final Rule on Transmission Planning and Cost Allocation*

On July 21, 2011, the FERC issued Order No. 1000, which revised the FERC's existing regulations governing the process for planning enhancements and expansions of the electric transmission grid in a particular region, along with the corresponding process for allocating the costs of such expansions. Order No. 1000 leaves to individual regions to determine whether a previously-approved project is subject to reevaluation and is therefore governed by the new rule.

Order No. 1000 requires, among other things, public utility transmission providers, such as the SPP, to participate in a process that produces a regional transmission plan satisfying certain standards, and requires that each such regional process consider transmission needs driven by public policy requirements (such as state or Federal policies favoring increased use of renewable energy resources). Order No. 1000 also directs public utility transmission providers to coordinate with neighboring transmission planning regions. In addition, Order No. 1000 establishes specific regional cost allocation principles and directs public utility transmission providers to participate in regional and interregional transmission planning processes that satisfy these principles.

On the issue of determining how entities are to be selected to develop and construct the specific transmission projects, Order No. 1000 directs public utility transmission providers to remove from the FERC-jurisdictional tariffs and agreements provisions that establish any Federal "right of first refusal" for the incumbent transmission owner (such as OG&E) regarding transmission facilities selected in a regional transmission planning process, subject to certain limitations. However, Order No. 1000 is not intended to affect the right of an incumbent transmission owner (such as OG&E) to build, own and recover costs for upgrades to its own transmission facilities, and Order No. 1000 does not alter an incumbent transmission owner's use and control of existing rights of way. Order No. 1000 also clarifies that incumbent transmission owners may rely on regional transmission facilities to meet their reliability needs or service obligations. The SPP currently has a "right of first refusal" for incumbent transmission owners and this provision has played a role in OG&E being selected by the SPP to build various transmission projects in Oklahoma. These changes to the "right of first refusal" apply only to "new transmission facilities," which are described as those subject to evaluation or reevaluation (under the applicable local or regional transmission planning process) subsequent to the effective date of the regulatory compliance filings required by the rule, which were filed on November 13, 2012.

OGE Energy cannot, at this time, determine the precise impact of Order No. 1000 on OG&E. OG&E has filed a petition for review in the D.C. Circuit relating to the same matter. Nevertheless, at the present time, OGE Energy has no reason to believe that the implementation of Order No. 1000 will impact OG&E's transmission projects currently under development and construction for which OG&E has received a notice to proceed from the SPP.

***OG&E Market-Based Rate Authority***

On June 29, 2012, OG&E filed its triennial market power update with the FERC to retain its market-based rate authorization in the SPP's energy imbalance service market but to surrender its market-based rate authorization for any market-based rate sales outside the SPP's energy imbalance service market. A FERC order is pending.

***OG&E Fuel Adjustment Clause Review for Calendar Year 2011***

On July 31, 2012, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2011 fuel adjustment clause and for a prudence review of OG&E's electric generation, purchased power and fuel procurement processes and costs in calendar year 2011. OG&E filed the necessary information and documents needed to satisfy the OCC's minimum filing requirement rules on October 1, 2012. On December 19, 2012, witnesses for the OCC Staff filed responsive testimony recommending that the OCC approve OG&E's fuel adjustment clause costs and recoveries for the calendar year 2011 and recommending that the OCC find that OG&E's electric generation, purchased power, fuel procurement and other fuel related practices, policies and decisions during calendar year 2011 were fair, just and reasonable and prudent. The Oklahoma Industrial Energy Consumers filed a statement of position on December 19, 2012 and did not challenge OG&E's application of its fuel adjustment clause or prudency. The Oklahoma Industrial Energy Consumers reserved its right to file rebuttal testimony, cross examine witnesses and amend its statement of position should circumstances change or additional information becomes available in the course of this proceeding. On January 7, 2013, the Oklahoma Attorney General filed a statement of position stating that after reviewing the case information the Attorney General has no reason at this time to dispute the findings of the OCC Staff. A hearing in this matter is scheduled for April 4, 2013.

***OG&E Crossroads Wind Farm***

As previously reported, OG&E signed memoranda of understanding in February 2010 for approximately 197.8 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the Crossroads wind farm. Also as part of this project, on June 16, 2011, OG&E entered into an interconnection agreement with the SPP for the Crossroads wind farm which allowed the Crossroads wind farm to interconnect at 227.5 MWs. On August 31, 2012, OG&E filed an application with the APSC requesting approval to recover the Arkansas portion of the costs of the Crossroads wind farm through a rider until such costs are included in OG&E's base rates as part of its next general rate proceeding. On December 14, 2012, the APSC Staff filed testimony recommending that the APSC find that the Crossroads wind farm is in the public interest and that it approve interim recovery through the Energy Cost Recovery Rider effective August 31, 2012. OG&E concurred with the APSC Staff’s recommendations. On January 16, 2013, the APSC granted a motion made by OG&E and the APSC Staff to cancel the hearing previously scheduled and issue an order based on the filed record. On February 22, 2013, the APSC directed OG&E to respond to two questions in order to complete the record upon which they may rule. OG&E believes it is reasonable to expect a final order from the APSC by the end of the first quarter.

***OG&E Fuel Adjustment Clause Review for Calendar Year 2009 Related to Enogex Gas Transportation and Storage Agreement***

As previously reported, under the terms of a settlement agreement reached in 2011 regarding the prudency of OG&E's fuel adjustment clause for 2009, OG&E agreed to hire a third party expert to evaluate its prospective gas transportation and storage needs and to identify options for meeting those needs. Upon completion of the third party evaluation, OG&E agreed to file a cause to address the third party's evaluation, recommendations and conclusions. On January 31, 2013, OG&E filed a cause that included OG&E's response to the final evaluations and conclusions of the third party consultant, Black & Veatch, and OG&E's assessment of transportation and storage needs for the next three to five years.

Also, as part of this matter, on August 9, 2012, OG&E filed an application with the OCC requesting: (i) an order finding that a one-year extension to April 30, 2014 of OG&E's gas transportation and storage agreement with Enogex is prudent, (ii) a waiver of the OCC's competitive procurement rules and (iii) finding that the one-year extension of the gas transportation and storage agreement complies with the OCC's affiliate transaction rules. On September 14, 2012, OG&E filed a settlement agreement in which all parties to this matter agreed to the one-year extension of the Enogex contract and cost recovery from ratepayers at the rates currently in effect. On October 25, 2012, the OCC issued an order approving the settlement agreement.

***Regulatory Assets and Liabilities***

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

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

At December 31, 2012 and 2011, OG&E had regulatory assets of $537.6 million and $523.9 million, respectively, and regulatory liabilities of $386.2 million and $276.4 million, respectively. See Note 1 of Notes to Consolidated Financial Statements for a further discussion.

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

**Rate Structures**

***Oklahoma***

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

OG&E offers several alternate customer programs and rate options. Under OG&E's Smart Grid enabled SmartHours® programs, "time-of-use" and "variable peak pricing" rates offer customers the ability to save on their electricity bills by shifting some of the electricity consumption to times when demand for electricity and costs are at their lowest. The guaranteed flat bill option for residential and small general service accounts allows qualifying customers the opportunity to purchase their electricity needs at a set monthly price for an entire year. Budget-minded customers that desire a fixed monthly bill may benefit from the guaranteed flat bill option. A second tariff rate option provides a "renewable energy" resource to OG&E's Oklahoma retail customers. This renewable energy resource is a Renewable Energy Credit purchase program and is available as a voluntary option to all of OG&E's Oklahoma retail customers. OG&E's ownership and access to wind resources makes the renewable option a possible choice in meeting the renewable energy needs of our conservation-minded customers. Another program being offered to OG&E's commercial and industrial customers is a voluntary load curtailment program called Load Reduction. This program provides customers with the opportunity to curtail usage on a voluntary basis when OG&E's system conditions merit curtailment action. Customers that curtail their usage will receive payment for their curtailment response. This voluntary curtailment program seeks customers that can curtail on most curtailment event days, but may not be able to curtail every time that a curtailment event is required. OG&E also offers certain qualifying customers "day-ahead price" and "flex price" rate options which allow participating customers to adjust their electricity consumption based on price signals received from OG&E. The prices for the "day-ahead price" and "flex price" rate options are based on OG&E's projected next day hourly operating costs.

OG&E also has two rate classes, Public Schools-Demand and Public Schools Non-Demand, that provide OG&E with flexibility to provide targeted programs for load management to public schools and their unique usage patterns. OG&E also provides service level, seasonal and time period fuel charge differentiation that allows customers to pay fuel costs that better reflect the underlying costs of providing electric service. Lastly, OG&E has a military base rider that demonstrates Oklahoma's continued commitment to our military partners.

The previously discussed rate options, coupled with OG&E's other rate choices, provide many tariff options for OG&E's Oklahoma retail customers. The revenue impacts associated with these options are not determinable in future years because customers may choose to remain on existing rate options instead of volunteering for the alternative rate option choices. Revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose alternative rate options.

OG&E's rate choices, reduction in cogeneration rates, acquisition of additional generation resources and overall low costs of production and deliverability are expected to provide valuable benefits for OG&E's customers for many years to come.

***Arkansas***

OG&E's standard tariff rates include a cost-of service component (including an authorized return on capital) plus an energy cost recovery mechanism that allows OG&E to pass through to customers the actual cost of fuel. OG&E offers several alternate customer programs and rate options. The "time-of-use" and "variable peak pricing" tariffs allow participating customers to save on their electricity bills by shifting some of the electricity consumption to times when demand for electricity is lowest. A second tariff rate option provides a "renewable energy" resource to OG&E's Arkansas retail customers. This renewable energy resource is a Renewable Energy Credit purchase program and is available as a voluntary option to all of OG&E's Arkansas retail customers. OG&E's ownership and access to wind resources makes the renewable option a possible choice in meeting the renewable energy needs of our conservation-minded customers. OG&E offers its commercial and industrial customers a voluntary load curtailment program called Load Reduction. This program provides customers with the opportunity to curtail usage on a voluntary basis and receive a billing credit when OG&E's system conditions merit curtailment action. OG&E offers certain qualifying customers a "day-ahead price" rate option which allows participating customers to adjust their electricity consumption based on a price signal received from OG&E. The day-ahead price is based on OG&E's projected next day hourly operating costs.

**Fuel Supply and Generation**

In 2012, 52 percent of the OG&E-generated energy was produced by coal-fired units, 42 percent by natural gas-fired units and six percent by wind-powered units. Of OG&E's 6,807 total MW capability reflected in the table under Item 2. Properties, 3,816 MWs, or 56 percent, are from natural gas generation, 2,542 MWs, or 37 percent, are from coal generation and 449 MWs, or seven percent, are from wind generation. Though OG&E has a higher installed capability of generation from natural gas units, it has been more economical to generate electricity for our customers using lower priced coal. Over the last five years, the weighted average cost of fuel used, by type, was as follows:

| Year ended December 31 *(In Kilowatt-Hour - cents)* | **2012** | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Natural gas | **2.930** | 4.328 | 4.638 | 3.696 | 8.455 |
| Coal | **2.310** | 2.064 | 1.911 | 1.747 | 1.153 |
| Weighted average | **2.437** | 2.897 | 3.012 | 2.474 | 3.337 |

The decrease in the weighted average cost of fuel in 2012 as compared to 2011 was primarily due to lower natural gas prices. The decrease in the weighted average cost of fuel in 2011 as compared to 2010 was primarily due to lower natural gas prices and lower natural gas generation. The increase in the weighted average cost of fuel in 2010 as compared to 2009 was primarily due to higher natural gas prices and increased natural gas generation. The decrease in the weighted average cost of fuel in 2009 as compared to 2008 was primarily due to decreased natural gas prices partially offset by increased coal transportation rates in 2009. A portion of these fuel costs is included in the base rates to customers and differs for each jurisdiction. The portion of recoverable fuel costs that is not included in the base rates is recovered through OG&E's fuel adjustment clauses that are approved by the OCC, the APSC and the FERC.

***Coal***

All of OG&E's coal-fired units, with an aggregate capability of 2,542 MWs, are designed to burn low sulfur western sub-bituminous coal. OG&E has contracted for approximately 60 percent of its forecasted annual coal usage via multi-year contracts that expire in 2015 and the remainder of its forecasted 2013 usage via one-year contracts that expire in 2013. In 2012, OG&E purchased 8.5 million tons of coal from various Wyoming suppliers. The combination of all coal has a weighted average sulfur content of 0.23 percent. Based upon the average sulfur content and EPA certified emission data, OG&E's coal units have an approximate emission rate of 0.5 lbs. of $SO_2$ per MMBtu. As discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations," emission limits are expected to become more stringent.

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

***Natural Gas***

OG&E has entered into multiple month term natural gas contracts for 26.1 percent of its 2013 annual forecasted natural gas requirements. Additional gas supplies to fulfill OG&E's remaining 2013 natural gas requirements will be acquired through additional requests for proposal in early to mid-2013, along with monthly and daily purchases, all of which are expected to be made at market prices.

OG&E utilizes a natural gas storage facility for storage services that allows OG&E to maximize the value of its generation assets. Storage services are provided by Enogex as part of Enogex's gas transportation and storage contract with OG&E. At December 31, 2012, OG&E had 1.5 million MMBtu's in natural gas storage valued at $4.6 million.

***Wind***

OG&E's current wind power portfolio includes: (i) the 120 MW Centennial wind farm, (ii) the 101 MW OU Spirit wind farm, (iii) the 227.5 MW Crossroads wind farm, (iv) access to up to 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma from a 15-year contract OG&E entered into with FPL Energy that expires in 2018, (v) access to up to 150 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with CPV Keenan that expires in 2030, (vi) access to up to 130 MWs of electricity generated at a wind farm in Dewey County, Oklahoma from a 20-year contract OG&E entered into with Edison Mission Energy that expires in 2030 and (vii) access to up to 60 MWs of electricity generated at a wind farm near Blackwell, Oklahoma from a 20-year contract OG&E entered into with NextEra Energy that expires in 2032.

**Safety and Health Regulation**

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

**NATURAL GAS MIDSTREAM OPERATIONS - ENOGEX**

**Overview**

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. Enogex's operations are now organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing.

On October 5, 2010, OGE Energy entered into an investment agreement with the ArcLight group, whereby the ArcLight group contributed $183,150,000 in exchange for a membership interest in Enogex Holdings. As a result of this transaction, the ArcLight group acquired an indirect interest in Enogex LLC and OGE Energy retained an indirect interest in Enogex LLC. The investment agreement provides the ArcLight group the opportunity to increase its ownership interest by providing equity funding for capital expenditures associated with Enogex's business plan. The transaction closed on November 1, 2010. As a result of the investment agreement described above and subsequent disproportionate contributions by the ArcLight group, at December 31, 2012, OGE Energy indirectly owns a 79.9 percent membership interest in Enogex Holdings.

As part of the investment agreement, OGE Energy and the ArcLight group have agreed to indemnify each other for breaches of representations, warranties and covenants contained in the investment agreement, and, in the case of OGE Energy, for certain tax matters related to the Company, in each case subject to customary thresholds and survival periods.

Pursuant to the Enogex Holdings LLC Agreement, OGE Holdings' and the ArcLight group's rights to designate directors to the Board of Directors of Enogex Holdings will be determined by percentage ownership. OGE Holdings was initially entitled to designate three directors, and the ArcLight group was initially entitled to designate one director. As its ownership position increases, the ArcLight group will be entitled to increasing board representation. The ArcLight group will also be entitled, at various ownership thresholds, to certain special board approval rights with respect to certain significant actions taken by Enogex Holdings, as well as to appoint additional directors for Enogex Holdings.

Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. If necessary, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings. Prior to January 1, 2012, the per unit equity price paid equaled the initial price that had been paid by the ArcLight group under the investment agreement. Beginning January 1, 2012, the equity price per unit is based on the equity value of Enogex Holdings. Subject to certain adjustments, including for material acquisitions, the equity value is calculated as 9.0 or 9.5 times trailing 12-month EBITDA, depending on the ArcLight group's ownership interest and whether the project has already been identified by Enogex Holdings.

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover OGE Energy's anticipated tax liabilities plus $12.5 million, to be distributed in proportion to each member's percentage ownership interest.

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

**Natural Gas Transportation and Storage**

***General***

Enogex owns and operates approximately 2,284 miles of intrastate natural gas transportation pipelines in Oklahoma with 2.08 TBtu/d of average daily throughput in 2012. Enogex provides fee-based firm and interruptible transportation services on both an intrastate basis and, pursuant to Section 311 of the Natural Gas Policy Act, on an interstate basis. Enogex's obligation to provide firm transportation service means that it is obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on Enogex's part, the shipper pays a specified demand or reservation charge, whether or not it utilizes the capacity. In most intrastate firm contracts, the shipper also pays a transportation or commodity charge with respect to quantities actually transported by Enogex. Enogex's obligation to provide interruptible transportation service means that it is obligated to transport natural gas nominated by the shipper only to the extent that it has available capacity. For this service, the shipper pays no demand or reservation charge but pays a transportation or commodity charge for quantities actually shipped. Enogex derives a substantial portion of its transportation revenues from firm transportation services and leased capacity. To the extent pipeline capacity is not needed for such firm transportation services and leased capacity, Enogex offers interruptible transportation services.

Enogex delivers natural gas to most interstate and intrastate pipelines and end-users connected to its systems from the Arkoma and Anadarko basins (including growth activity in the Granite Wash play, Cana/Woodford Shale play and the Colony Wash play in western Oklahoma and the Granite Wash play in the Wheeler County, Texas area, which is located in the Texas Panhandle). At December 31, 2012, Enogex was connected to 13 third-party natural gas pipelines and had 63 interconnect points. These third-party natural gas pipelines include ANR Pipeline, CenterPoint Energy Gas Transmission Co., El Paso Natural Gas Pipeline, Gulf Crossing Pipeline Company LLC, MEP, Natural Gas Pipeline Company of America, Northern Natural Gas Company, Oneok Gas Transmission, Ozark Gas Transmission, L.L.C., Panhandle Eastern Pipe Line, Postrock KPC Pipeline, LLC, Southern Star Central Gas Pipeline (formerly Williams Central) and Western Farmers Electric Cooperative. Further, Enogex is connected to 37 end-user customers, including 15 natural gas-fired electric generation facilities in Oklahoma.

Enogex also owns and operates two underground natural gas storage facilities in Oklahoma operating at a combined working gas level of 24 billion cubic feet with 650 MMcf/d of maximum withdrawal capacity and 650 MMcf/d of injection capacity. Enogex offers both fee-based firm and interruptible storage services. Storage services offered under Section 311 of the Natural Gas Policy Act are pursuant to terms and conditions specified in Enogex's statement of operating conditions for gas storage and at market-based rates.

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

***Customers and Contracts***

Enogex's major transportation customers are OG&E and PSO, the second largest electric utility in Oklahoma. Enogex provides gas transmission delivery services to all of PSO's natural gas-fired electric generation facilities in Oklahoma under a firm intrastate transportation contract. The PSO contract and the OG&E contract provide for a monthly demand charge plus variable transportation charges including fuel. The stated term of the PSO contract expired January 1, 2013, but the contract remains in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 180 days prior to the commencement of the next succeeding annual period. Because neither party provided notice of termination 180 days prior to January 1, 2013, the PSO contract will remain in effect at least through January 1, 2014. The stated term of the OG&E contract expired April 30, 2009, but the contract remains in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 180 days prior to the commencement of the next succeeding annual period. Because neither party provided notice of termination 180 days prior to May 1, 2013, the OG&E contract will remain in effect at least through April 30, 2014. As part of the no-notice load following contract with OG&E, Enogex provides natural gas storage services for OG&E. Enogex has been providing natural gas storage services to OG&E since August 2002 when it acquired the Stuart Storage Facility. Demand for natural gas on Enogex's system is usually greater during the summer, primarily due to demand by natural gas-fired electric generation facilities to serve residential and commercial electricity requirements. In 2012, 2011 and 2010, revenues from Enogex's firm intrastate natural gas transportation and storage contracts were $131.5 million, $130.7 million and $116.6 million, respectively, of which $47.5 million in each year was attributed to OG&E and $15.3 million in each year was attributed to PSO. Revenues from Enogex's firm intrastate transportation and storage contracts represented 27 percent of Enogex's consolidated gross margin in 2012, 30 percent in 2011 and 28 percent in 2010.

***Competition***

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

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

***Regulation***

The transportation rates charged by Enogex for transporting natural gas in interstate commerce are subject to the jurisdiction of the FERC under Section 311 of the Natural Gas Policy Act. Rates to provide such service must be "fair and equitable" under the Natural Gas Policy Act and are subject to review and approval by the FERC at least once every five years (previously a triennial requirement). The rate review may, but will not necessarily, involve an administrative-type hearing before a FERC Staff panel and an administrative appellate review. In the past, Enogex has successfully settled, rather than litigated, its Section 311 rate cases. Enogex currently has two zones under its Section 311 rate structure – an East Zone and a West Zone. Enogex historically offered only interruptible Section 311 service in both zones. Enogex began to offer firm Section 311 service in the East Zone on April 1, 2009 and in the West Zone on March 1, 2011.

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

**Completed Regulatory Matters**

***Enogex 2011 Fuel Filing***

On February 28, 2011, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the upcoming fuel year (April 1, 2011 through March 31, 2012). Along with the revised fuel percentages, Enogex also requested authority to revise its statement of operating conditions to permanently change the annual filing date to February 28. On July 6, 2012, Enogex submitted a compliance filing to synchronize the 2011 fuel filing with the revised statement of operating conditions filed on May 31, 2012 in compliance with the FERC's order approving Enogex's 2011 Section 311 rate case settlement. In October 2012, the FERC accepted Enogex's proposed zonal fuel percentages.

***Enogex 2012 Fuel Filing***

On February 24, 2012, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the 2012 fuel year (April 1, 2012 through March 31, 2013). On July 6, 2012, Enogex submitted a compliance filing to synchronize the 2012 fuel filing with the revised statement of operating conditions filed on May 31, 2012 in compliance with the FERC's order approving Enogex's 2011 Section 311 rate case settlement. In October 2012, the FERC accepted Enogex's proposed zonal fuel percentages.

***Enogex Storage Statement of Operating Conditions Filing***

On August 31, 2010, Enogex filed a new statement of operating conditions applicable to storage services with the FERC that replaced Enogex's existing storage statement of operating conditions effective July 30, 2010. Among other things, the new storage statement of operating conditions updates the general terms and conditions for providing storage services. On December 7, 2012, the FERC issued an order approving Enogex's revised storage statement of operating conditions, effective August 31, 2010.

***Enogex FERC Section 311 2011 Rate Case***

On January 28, 2011, Enogex submitted a new rate filing to the FERC to set the maximum rate for a new firm Section 311 transportation service in the West Zone of its system and to revise the currently effective maximum rates for Section 311 interruptible transportation service in the East Zone and West Zone. Along with establishing the rate for a new firm service in the West Zone, Enogex's filing requested a decrease in the maximum interruptible zonal rates in the West Zone and to retain the currently effective rates for firm and interruptible services in the East Zone. Enogex reserved the right to implement the higher rates for firm and interruptible services in the East Zone supported by the cost of service to the extent an expeditious settlement agreement cannot be reached in the proceeding. Enogex proposed that the rates be placed into effect on March 1, 2011. On January 10, 2012, Enogex filed a settlement agreement with the FERC. On May 4, 2012, the FERC issued an order approving the settlement agreement in this matter, subject to the submission of a compliance filing to place the settlement rates into effect as of March 1, 2011, which compliance filing was subsequently filed on May 31, 2012. The FERC also requested that Enogex file a revised statement of operating conditions, which was subsequently filed on May 31, 2012. As part of the settlement agreement in this matter, Enogex made refunds of $0.2 million to affected customers on June 15, 2012 and submitted a report to the FERC on July 6, 2012 showing the refund payment calculation. On February 21, 2013, the FERC issued an order approving the refund report.

***Recent System Expansions***

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

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

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

In August 2010, Enogex completed construction of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Aid in Construction payments of $36.4 million received in excess of construction costs were recognized as Deferred Revenues on the Company's Consolidated Balance Sheet and are being amortized on a straight-line basis of $1.2 million per year over the life of the related firm transportation service agreement under which service commenced in June 2011.

**Natural Gas Gathering and Processing**

***General***

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

Enogex's gathering system includes approximately 6,640 miles of intrastate natural gas gathering pipelines in Oklahoma and Texas with 1.41 TBtu/d of average daily gathered volumes in 2012. Enogex owns and operates nine natural gas processing plants, with a current total inlet capacity of 1,305 MMcf/d and has contracted to have access to up to 90 MMcf/d of capacity in three third-party plants. Where the quality of natural gas received dictates the removal of NGLs, such gas is aggregated through the gathering system to the inlet of one or more processing plants operated or utilized by Enogex. The resulting processed stream of natural gas is then delivered from the tailgate of each plant into Enogex's intrastate natural gas transportation system for the nine processing plants that Enogex owns. In 2012, Enogex extracted and sold 867 million gallons of NGLs.

Enogex also has a 50 percent interest in Atoka, which previously operated a 20 MMcf/d refrigeration processing plant which processed gas gathered in the Atoka area. The processing plant was leased on a month-to-month basis. In August 2011, management made a decision to use third-party processing exclusively for gathered volumes dedicated to Atoka and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement.

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

- *Fee-based arrangements*. Under these arrangements, Enogex generally is paid a fixed fee for performing the gathering and processing service. This fee is directly related to the volume of natural gas that flows through Enogex's system and is not directly dependent on commodity prices. However, a sustained decline in commodity prices could result in a decline in volumes and, thus, a decrease in Enogex's fee revenues. These arrangements provide stable cash flows, but minimal, if any, upside in higher commodity price environments. At December 31, 2012, these arrangements accounted for 35 percent of Enogex's natural gas processed volumes.
- *Percent-of-proceeds and percent-of-liquids arrangements*. Under these arrangements, Enogex generally gathers raw natural gas from producers at the wellhead, transports the gas through its gathering system, processes the gas and sells the processed gas and/or NGLs at prices based on published index prices. These arrangements provide upside in high commodity price environments, but result in lower margins in low commodity price environments. The price paid to producers is based on an agreed percentage of the proceeds of the sale of processed natural gas, NGLs or both or the expected proceeds based on an index price. We refer to contracts in which Enogex shares in specified percentages of the proceeds from the sale of natural gas and NGLs as percent-of-proceeds arrangements and in which Enogex receives proceeds from the sale of NGLs or the NGLs themselves as compensation for its processing services as percent-of-liquids arrangements. Under percent-of-proceeds arrangements, Enogex's margin correlates directly with the prices of natural gas and NGLs. Under percent-of-liquids arrangements, Enogex's margin correlates directly with the prices of NGLs. At December 31, 2012, Enogex's percent-of-proceeds and percent-of-liquids processing arrangements accounted for 16 percent and 28 percent, respectively, of Enogex's natural gas processed volumes.

- *Keep-whole arrangements*. Enogex processes raw natural gas to extract NGLs and returns to the producer the full gas equivalent British thermal unit value of raw natural gas received from the producer in the form of either processed gas or its cash equivalent. Enogex is entitled to retain the processed NGLs and to sell them for its own account. Accordingly, Enogex's margin is a function of the difference between the value of the NGLs produced and the cost of the processed gas used to replace the thermal equivalent of those NGLs. These arrangements can provide large profit margins in favorable commodity price environments, but also can be subject to losses if the cost of natural gas exceeds the value of its thermal equivalent of NGLs. Many of Enogex's keep-whole contracts include provisions that reduce its commodity price exposure, including conditioning floors (such as the default processing fee described below) that allow the keep-whole contract to be charged a fee if the NGLs have a lower value than their gas equivalent British thermal unit value in natural gas. At December 31, 2012, these arrangements accounted for 21 percent of Enogex's natural gas processed volumes.

Total processable volumes during 2012 were 1.00 Tbtu/d. Processable volumes are the natural gas production that are on Enogex's gathering systems that are available to be processed, some of which is moved off of the system and is not processed under one of Enogex's processing agreements. Processable volumes include condensate volumes which are captured in the gathering pipeline and therefore not included in plant inlet volumes.

In August 2011, Enogex and one of its five largest customers entered into new agreements, effective July 1, 2011, relating to the customer's natural gas gathering and processing volumes on the Oklahoma portion of Enogex's system. The effect of this new arrangement is that (i) the acreage dedicated by the customer to Enogex for gathering and processing in Oklahoma has been increased for an extended term and (ii) the processing arrangement has been converted from keep-whole to fixed fee. This customer's converted volumes represented 8.4 percent of total inlet volumes from July 1, 2011 to December 31, 2011. As a result, Enogex has recorded $7.1 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2012, which are expected to be recognized based on the estimated average fee per MMBtu processed by the end of 2014.

On January 2, 2013, Enogex and one of its five largest customers entered into new agreements, effective January 1, 2013, relating to the customer's gathering and processing volumes on the Texas portion of Enogex's system. The effects of this new arrangement are (i) a fixed fee processing agreement replaces the previous keep-whole agreement, (ii) the acreage dedicated by the customer to Enogex for gathering and processing in Texas has been increased for an extended term and (iii) the sale by Enogex of certain gas gathering assets in the Texas Panhandle portion of Enogex's system to this customer for cash proceeds of approximately $35 million. The sale of these assets was approved by the Company's and Enogex's Board of Directors in November 2012, therefore these assets were classified as held for sale on the Company's Consolidated Balance Sheet at December 31, 2012. Enogex expects to recognize a pre-tax gain of approximately $10 million in the first quarter of 2013 in its natural gas gathering and processing segment from the sale of these assets.

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

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

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

In order to meet the growing requirements of its customers, Enogex continues to evaluate the need to expand its processing capabilities on the "super-header" gathering system, such as the 200 MMcf/d processing plant in Canadian County which was placed in service in December 2011, the 200 MMcf/d processing plant in Wheeler County, Texas which was placed into service in August 2012 and the 200 MMcf/d processing plant which is expected to be installed in Custer County, Oklahoma by the end of 2013.

***Customers and Contracts***

The natural gas remaining after processing is primarily taken in kind by the producer customers into Enogex's transportation pipelines for redelivery either: (i) to on-system customers such as the electric generation facilities of OG&E, PSO, other independent power producers and other end-users or (ii) into downstream interstate pipelines. Enogex's NGLs are typically sold to NGLs marketers and end-users, its condensate liquid production is typically sold to marketers and refineries and its propane is typically sold in the local market to wholesale distributors. Enogex's key natural gas producer customers in 2012 included Chesapeake Energy Marketing Inc., Apache Corporation and Devon Energy Production Company, L.P. In 2012, these customers accounted for 19.6 percent, 17.8 percent and 10.6 percent, respectively, of Enogex's gathering and processing volumes. In 2012, Enogex's top 10 natural gas producer customers accounted for 73.0 percent of Enogex's gathering and processing volumes.

***Competition***

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

***Regulation***

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

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

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

***Recent System Expansions***

Over the past several years, Enogex has initiated multiple organic growth projects. Currently, in Enogex's natural gas gathering and processing business, organic growth capital expenditures are focused on expansions on the west side of Enogex's gathering system, primarily in the Cana/Woodford Shale play and the Greater Granite Wash area, which includes the Colony Wash play in western Oklahoma and the Cleveland, Marmaton, Tonkawa and Granite Wash plays in western Oklahoma and in the Texas Panhandle.

In December 2011, Enogex completed construction of a cryogenic processing plant in Canadian County, Oklahoma, which added 200 MMcf/d of natural gas processing capacity to Enogex's system, and is supported by the installation of inlet and residue compression and the installation of 31 miles of 20-inch gathering pipeline, as well as 11 miles of 24-inch transmission pipeline providing takeaway capacity from the plant tailgate.

In August 2012, Enogex completed construction of its cryogenic processing plant in Wheeler County, Texas, which added 200 MMcf/d of rich gas processing capacity to Enogex's system, and is supported by the installation of 9,400 horsepower of field compression, as well as 6,000 horsepower of inlet compression to facilitate additional flexibility in the operation of Enogex's "super-header" gathering system. The remainder of the inlet compression facilities is expected to be in service during the second quarter of 2013.

In support of significant long-term acreage dedications from its customers in the area, Enogex has expanded its gathering infrastructure in western Oklahoma and the Texas Panhandle. These expansions included the installation of 39,700 horsepower of low pressure compression and 235 miles of gathering pipe across the area, which was completed during the third quarter of 2012.

In support of significant long-term acreage dedications from its customers in the area, Enogex is expanding its gathering infrastructure in southern Oklahoma. The initial phase of these expansions include the installation of approximately 20,000 horsepower of compression and approximately 100 miles of gathering pipeline, which are expected to be in service by the end of the first quarter of 2013. The remainder of the expansion includes the installation of approximately 50,000 horsepower of compression and approximately 300 miles of gathering pipeline, which are expected to be in service by the end of 2013.

Enogex is constructing a cryogenic processing plant in Custer County, Oklahoma, which is expected add 200 MMcf/d of natural gas processing capacity to Enogex's system, and is expected to be supported by the installation of 6,000 horsepower of inlet compression and four miles of transmission pipeline. This plant will be connected to the Enogex "super-header" gathering system and is expected to be in service by the end of 2013.

***Divestitures***

**Texas Panhandle Gathering Divestiture**

On January 2, 2013, Enogex and one of its five largest customers entered into new agreements, effective January 1, 2013, relating to the customer's gathering and processing volumes on the Texas portion of Enogex's system. The effects of this new arrangement are (i) a fixed fee processing agreement replaces the previous keep-whole agreement, (ii) the acreage dedicated by the customer to Enogex for gathering and processing in Texas has been increased for an extended term and (iii) the sale by Enogex of certain gas gathering assets in the Texas Panhandle portion of Enogex's system to this customer for cash proceeds of approximately $35 million. The sale of these assets was approved by the Company's and Enogex's Board of Directors in November 2012, therefore these assets were classified as held for sale on the Company's Consolidated Balance Sheet at December 31, 2012. Enogex expects to recognize a pre-tax gain of approximately $10 million in the first quarter of 2013 in its natural gas gathering and processing segment from the sale of these assets.

**Harrah Gathering and Processing Divestiture**

On April 1, 2011, Enogex completed the sale of its Harrah processing plant (38 MMcf/d of capacity) and the associated Wellston and Davenport gathering assets. The proceeds from the sale were $15.9 million and Enogex recorded a pre-tax gain in the second quarter of 2011 of $3.7 million in its natural gas gathering and processing segment.

***Gas Gathering Acquisitions***

In addition to the organic growth projects described above, the Company believes that the acquisition transactions described below will provide Enogex with key new opportunities in the greater Granite Wash area.

**Western Oklahoma Gathering Acquisition**

On September 23, 2011, Enogex entered into the following agreements: an agreement with Cordillera, Oxbow and West Canadian Midstream LLC pursuant to which Enogex agreed to acquire 100 percent of the membership interest in Roger Mills Gas Gathering, LLC, an Oklahoma limited liability company that owns an approximately 60-mile natural gas gathering system located in Roger Mills County and Ellis County, Oklahoma; an agreement with Cordillera and Oxbow pursuant to which Enogex agreed to acquire an approximately 30-mile natural gas gathering system located in Roger Mills County, Oklahoma; and agreements with Cordillera and other producers pursuant to which such producers agreed to provide Enogex with long-term acreage dedication in the area served by the gathering systems encompassing approximately 100,000 net acres. The gathering systems are located in the Granite Wash area. The aggregate purchase price for these transactions was $200.4 million which was paid in cash primarily from contributions from OGE Energy and the ArcLight group as well as cash generated from operations and bank borrowings. The transactions closed on November 1, 2011. In support of these acquisitions, Enogex constructed 20 miles of 16-inch gathering pipe and over 11,000 horsepower of low pressure compression in 2012.

**Granite Wash Gathering Acquisition**

On August 1, 2012, Enogex entered into agreements with Chesapeake Midstream Gas Services, L.L.C. and Mid-America Midstream Gas Services, L.L.C., wholly-owned subsidiaries of Access Midstream Partners, L.P. and Chesapeake Midstream Development, L.P., respectively, pursuant to which Enogex agreed to acquire approximately 235 miles of natural gas gathering pipelines, right-of-ways and certain other midstream assets that provide natural gas gathering services in the greater Granite Wash area. The transactions closed on August 31, 2012. The aggregate purchase price for these transactions was approximately $78.6 million including reimbursement for certain permitted capital expenditures incurred during the period beginning June 1, 2012 and ending August 31, 2012. Enogex utilized cash generated from operations and bank borrowings to fund the purchase. In addition, Enogex also incurred acquisition-related costs of $3.5 million for sales taxes on acquired assets, which are included in taxes other than income. Enogex expects the purchase price allocations to be completed by the end of the first quarter of 2013.

In connection with these agreements, Enogex entered into a gas gathering and processing agreement with Chesapeake effective September 1, 2012 pursuant to which Enogex began providing fee-based natural gas gathering, compression, processing and transportation services to Chesapeake with respect to certain acreage dedicated by Chesapeake.

***Enogex Cox City Plant Fire***

On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. The damaged train was replaced and the facility was returned to full service in September 2011. The total cost necessary to return the facility back to full service was $29.6 million. In the fourth quarter of 2011, Enogex received a partial insurance reimbursement of $7.4 million and recognized a gain of $3.0 million on insurance proceeds. In March 2012, Enogex reached a settlement agreement with its insurers in this matter. As a result of the settlement agreement, Enogex received additional reimbursements of $7.6 million and recognized a gain of $7.5 million on insurance proceeds in 2012.

**Safety and Health Regulation**

Certain of Enogex's facilities are subject to pipeline transportation regulations, including the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The Pipeline and Hazardous Materials Safety Administration regulates safety requirements in the design, construction, operation and maintenance of applicable natural gas and hazardous liquid pipeline facilities. The Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 require mandatory inspections and enforcement for all U.S. hazardous liquid and natural gas transportation pipelines, including some gathering lines in high population areas. The U.S. Department of Transportation has developed regulations implementing the Pipeline Safety Improvement Act of 2002 that require pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in high-consequence areas where threats pose the greatest risk to people and their property. For example, the U.S. Department of Transportation has adopted regulations requiring pipeline operators to develop integrity management programs for their applicable pipelines. In 2012, Enogex incurred $13.7 million of capital expenditures and operating costs for pipeline integrity management. Enogex currently estimates that it will incur capital expenditures and operating costs of between $100 million and $160 million from 2013 to 2017 in connection with pipeline integrity management. The estimated capital expenditures and operating costs include Enogex's estimates for the assessment, remediation and prevention or other mitigation that may be determined to be necessary. At this time, Enogex cannot predict the ultimate costs of its integrity management program and compliance with this regulation because those costs will depend on the number and extent of any repairs found to be necessary. Enogex will continue to assess, remediate and maintain the integrity of its pipelines. The results of these activities could cause Enogex to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

On December 13, 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which the President signed into law on January 3, 2012. Among other things, the law requires additional verification of pipeline infrastructure records by Enogex and other intrastate and interstate pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. Where records are inadequate to confirm the maximum allowable operating pressure, the PHMSA will require the operator to re-confirm the maximum allowable operating pressure, a process that could cause temporary or permanent limitations on throughput for affected pipelines. This law required PHMSA to direct pipeline operators to verify the maximum allowable operating pressure of their pipelines by July 3, 2

012, and to submit documentation to PHMSA by July 3, 2013. This law also raises the maximum penalty for violating pipeline safety rules to $0.2 million per violation per day up to $2.0 million for a related series of violations. For further information regarding this Act and potential regulations, see Note 16 of Notes to Consolidated Financial Statements. At this time, the Company is not able to estimate the capital, operating or other costs that may be required to comply with this law and any related PHMSA regulations that may be promulgated, but such costs could be significant.

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

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

**ENVIRONMENTAL MATTERS**

**General**

The activities of OG&E and Enogex are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way it can handle or dispose of their wastes, requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. OG&E and Enogex believe that their operations are in substantial compliance with current Federal, state and local environmental standards.

The trend in environmental regulation, however, is to place more restrictions and limitations on activities that may affect the environment. OG&E and Enogex cannot assure that future events, such as changes in existing laws, the promulgation of new laws or regulations, or the development or discovery of new facts or conditions will not cause them to incur significant costs. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

It is estimated that OG&E's and Enogex's total expenditures to comply with environmental laws, regulations and requirements for 2013 will be $63.0 million and $6.4 million, respectively, of which $45.3 million and $0.7 million, respectively, are for capital expenditures. It is estimated that OG&E's and Enogex's total expenditures to comply for environmental laws, regulations and requirements for 2014 will be $37.7 million and $6.3 million, respectively, of which $19.2 million and $0.5 million, respectively, are for capital expenditures. The amounts for OG&E above include capital expenditures for low NOX burners and exclude certain other capital expenditures as discussed in the capital expenditures table and related footnote D in "Finance and Construction" below. The Company's management believes that all of its operations are in substantial compliance with current Federal, state and local environmental standards. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

For a further discussion of environmental matters that may affect the Company, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations."

**FINANCE AND CONSTRUCTION**

**Future Capital Requirements and Financing Activities**

***Capital Requirements***

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and Enogex. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, hedging activities, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" for a discussion of the Company's capital requirements.

***Capital Expenditures***

The Company's consolidated estimates of capital expenditures for the years 2013 through 2017 are shown in the following table. These capital expenditures represent the base maintenance capital expenditures (i.e., capital expenditures to maintain and operate the Company's businesses) plus capital expenditures for known and committed projects.

| *(In millions)* | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|
| OG&E Base Transmission | $ 65 | $ 50 | $ 50 | $ 50 | $ 50 |
| OG&E Base Distribution | 175 | 175 | 175 | 175 | 175 |
| OG&E Base Generation | 80 | 75 | 75 | 75 | 75 |
| OG&E Other | 15 | 15 | 15 | 15 | 15 |
| Total OG&E Base Transmission, Distribution, Generation and Other | 335 | 315 | 315 | 315 | 315 |
| OG&E Known and Committed Projects: | | | | | |
| Transmission Projects: | | | | | |
| Balanced Portfolio 3E Projects (A) | 205 | 25 | — | — | — |
| SPP Priority Projects (B) | 165 | 110 | — | — | — |
| SPP Integrated Transmission Projects (C) | 5 | 5 | — | 40 | 40 |
| Total Transmission Projects | 375 | 140 | — | 40 | 40 |
| Other Projects: | | | | | |
| Smart Grid Program | 25 | 25 | 10 | 10 | — |
| System Hardening | 15 | — | — | — | — |
| Environmental - low NOX burners | 30 | 20 | 25 | 20 | — |
| Total Other Projects | 70 | 45 | 35 | 30 | — |
| Total OG&E Known and Committed Projects | 445 | 185 | 35 | 70 | 40 |
| Total OG&E (D) | 780 | 500 | 350 | 385 | 355 |
| Enogex LLC Base Maintenance | 50 | 55 | 55 | 55 | 55 |
| Enogex LLC Known and Committed Projects: | | | | | |
| Western Oklahoma / Texas Panhandle Gathering Expansion | 380 | 180 | 140 | 80 | 65 |
| Other Gathering Expansion | 25 | 15 | 10 | 10 | 10 |
| Total Enogex LLC Known and Committed Projects | 405 | 195 | 150 | 90 | 75 |
| Total Enogex LLC (E) | 455 | 250 | 205 | 145 | 130 |
| OGE Energy | 10 | 10 | 10 | 10 | 10 |
| Total capital expenditures | $ 1,245 | $ 760 | $ 565 | $ 540 | $ 495 |

(A) Balanced Portfolio 3E includes three projects to be built by OG&E and includes: (i) construction of 135 miles of transmission line from OG&E's Seminole substation in a northeastern direction to OG&E's Muskogee substation at an estimated cost of $175 million for OG&E, which is expected to be in service by late 2013, (ii) construction of 96 miles of transmission line from OG&E's Woodward District Extra High Voltage substation in a southwestern direction to the Oklahoma/Texas Stateline to a companion transmission line to be built by Southwestern Public Service to its Tuco substation at an estimated cost of $115 million for OG&E, which is expected to be in service by mid-2014 and (iii) construction of 39 miles of transmission line from OG&E's Sooner substation in an eastern direction to the Grand River Dam Authority Cleveland substation at an estimated cost of $45 million for OG&E, which was placed in service in February 2013.

(B) The Priority Projects consist of several transmission projects, two of which have been assigned to OG&E. The 345 kilovolt projects include: (i) construction of 99 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line to be built by Southwestern Public Service to its Hitchland substation in the Texas Panhandle at an estimated cost of $185 million for OG&E, which is expected to be in service by mid-2014 and (ii) construction of 77 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line at the Kansas border to be built by either Mid-Kansas Electric Company or another company assigned by Mid-Kansas Electric Company at an estimated cost of $150 million to OG&E, which is expected to be in service by late 2014. OG&E began construction on the Hitchland project in November 2012 and expects to begin construction on the Kansas project in June 2013.

(C) On January 31, 2012, the SPP approved the Integrated Transmission Plan Near Term and Integrated Transmission Plan 10-year projects. These plans include two projects to be built by OG&E: (i) construction of 47 miles of transmission line from OG&E's Gracemont substation in a northwestern direction to a companion transmission line to be built by American Electric Power to its Elk City substation at an estimated cost of $75 million for OG&E, which is expected to be in service by early 2018, and (ii) construction of 126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation in a southeastern direction to OG&E's Cimarron substation and construction of a new substation on this transmission line, the Mathewson substation, at an estimated cost of $210 million for OG&E, which is expected to be in service by early 2021. On April 9, 2012, OG&E received a notice to construct these projects from the SPP. On June 26, 2012, OG&E responded to the SPP that OG&E will construct the projects discussed above and is moving forward with more detailed cost estimates that must be reviewed and approved by the SPP. OG&E and American Electric Power are currently in discussions regarding how much of the 94 mile Elk City to Gracemont transmission line will be built by OG&E and American Electric Power. American Electric Power has argued for a larger portion of such transmission line than the traditional 50 percent split. The capital expenditures related to these projects are presented in the summary of capital expenditures for known and committed projects above.

(D) The capital expenditures above exclude any environmental expenditures associated with:

- Pollution control equipment related to controlling $SO_2$ emissions under the regional haze requirements due to the uncertainty regarding the approach and timing for such pollution control equipment. The $SO_2$ emissions standards in the EPA's FIP could require the installation of Dry Scrubbers or fuel switching. OG&E estimates that installing such Dry Scrubbers could cost more than $1.0 billion. The FIP is being challenged by OG&E and the state of Oklahoma. On June 22, 2012, OG&E was granted a stay of the FIP by the U.S. Court of Appeals for the Tenth Circuit, which delays the timing of required implementation of the $SO_2$ emissions standards in the rule. The merits of the appeal have been fully briefed, and oral argument is scheduled to occur on March 6, 2013. Neither the outcome of the challenge to the FIP nor the timing of any required capital expenditures can be predicted with any certainty at this time, but such capital expenditures could be significant.
- Installation of control equipment for compliance with MATS by a deadline of April 16, 2015, with the possibility of a one-year extension. OG&E is currently planning to utilize activated carbon injection and low levels of dry sorbent injection at each of its five coal-fired units. Due to various uncertainties about the final design, the potential use of this technology relating to regional haze measures and the specifications for the control equipment, the resulting cost estimates currently range from $34 million to $72 million per unit.

OG&E is currently evaluating options to comply with environmental requirements. For further information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations" below.

(E) These capital expenditures represent 100 percent of Enogex LLC's capital expenditures, of which a portion may be funded by the ArcLight group. Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. If necessary, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets and at Enogex LLC, will be evaluated based upon their impact upon achieving the Company's financial objectives. The capital expenditure projections related to Enogex LLC in the table above reflect base market conditions at February 27, 2013 and do not reflect the potential opportunity for a set of growth projects that could materialize. Also, if drilling activity declines in the future, this could reduce Enogex's capital expenditures in the table above.

*Pension and Postretirement Benefit Plans*

During 2012 and 2011, OGE Energy made contributions to its Pension Plan of $35 million and $50 million, respectively, to help ensure that the Pension Plan maintains an adequate funded status. During 2013, OGE Energy expects to contribute up to $35 million to its Pension Plan. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Future Capital Requirements and Financing Activities" for a discussion of OGE Energy's pension and postretirement benefit plans.

*Common Stock Dividends*

At the Company's November 2012 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 $0.4175 per share from $0.3925 per share effective with the Company's first quarter 2013 dividend. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Future Capital Requirements and Financing Activities" for a further discussion.

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

*Short-Term Debt and Credit Facilities*

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $430.9 million and $277.1 million at December 31, 2012 and 2011, respectively. The weighted-average interest rate on short-term debt at December 31, 2012 was 0.43 percent. The average balance of short-term debt in 2012 was $451.0 million at a weighted-average interest rate of 0.45 percent. The maximum month-end balance of short-term debt in 2012 was $608.2 million. At December 31, 2012, Enogex had no outstanding borrowings under its revolving credit agreement as compared to $150.0 million at December 31, 2011. As Enogex LLC's credit agreement matures on December 13, 2016, along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Consolidated Balance Sheets. At December 31, 2012, the Company had $1,116.9 million of net available liquidity under its revolving credit agreements. 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, 2013 and ending December 31, 2014. At December 31, 2012, the Company had $1.8 million in cash and cash equivalents. See Note 13 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

*Expected Issuance of Long-Term Debt*

OG&E expects to issue up to $250 million of long-term debt in the first half of 2013, depending on market conditions, to fund capital expenditures, repay short-term borrowings and for general corporate purposes.

*Common Stock*

The Company expects to issue between $12 million and $15 million of common stock in its Automatic Dividend Reinvestment and Stock Purchase Plan in 2013. See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

*Minimum Quarterly Distributions by Enogex Holdings*

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover OGE Energy's anticipated tax liabilities plus $12.5 million, to be distributed in proportion to each member's percentage ownership interest.

**EMPLOYEES**

The Company and its subsidiaries had 3,377 employees at December 31, 2012.

**EXECUTIVE OFFICERS**

The following persons were Executive Officers of the Registrant as of February 27, 2013:

| Name | Age | Title |
|---|---|---|
| Peter B. Delaney | 59 | Chairman of the Board, President and Chief Executive Officer - OGE Energy Corp. |
| Sean Trauschke | 46 | Vice President and Chief Financial Officer - OGE Energy Corp. |
| E. Keith Mitchell | 50 | President and Chief Operating Officer - Enogex Holdings |
| Stephen E. Merrill | 48 | Chief Operating Officer of Enogex LLC |
| William J. Bullard | 64 | Assistant General Counsel - OGE Energy Corp. |
| Scott Forbes | 55 | Controller and Chief Accounting Officer - OGE Energy Corp. |
| Patricia D. Horn | 54 | Vice President - Governance, Environmental and Corporate Secretary - OGE Energy Corp. |
| Gary D. Huneryager | 62 | Vice President - Internal Audits - OGE Energy Corp. |
| Jesse B. Langston | 50 | Vice President - Retail Energy - OG&E |
| Jean C. Leger, Jr. | 54 | Vice President - Utility Operations - OG&E |
| Cristina F. McQuistion | 48 | Vice President - Strategic Planning, Performance Improvement and Chief Information Officer - OGE Energy Corp. |
| Max J. Myers | 38 | Treasurer - OGE Energy Corp. |
| Jerry A. Peace | 50 | Chief Risk Officer - OGE Energy Corp. |
| Paul L. Renfrow | 56 | Vice President - Public Affairs, Human Resources and Health & Safety - OGE Energy Corp. |

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Delaney, Trauschke, Bullard, Forbes, Huneryager, Myers, Peace, Renfrow and Ms. Horn and Ms. McQuistion are also officers of OG&E. Messrs. Delaney, Trauschke, Mitchell, Myers and Ms. Horn are also officers of Enogex Holdings and/or its subsidiaries. Each Executive Officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Shareowners, currently scheduled for May 16, 2013.

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

| Name | | Business Experience |
|---|---|---|
| Peter B. Delaney | 2012 - Present: | Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp. and OG&E |
| | 2010 - 2011: | Chairman of the Board and Chief Executive Officer of OGE Energy Corp. and OG&E |
| | 2010 - Present: | Chief Executive Officer of Enogex Holdings |
| | 2008 - Present: | Chief Executive Officer of Enogex LLC |
| | 2008 - 2010: | Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp. and OG&E |
| | 2008: | Chief Executive Officer of Enogex Inc. |
| Sean Trauschke | 2009 - Present: | Vice President and Chief Financial Officer of OGE Energy Corp. and OG&E |
| | 2010 - Present: | Chief Financial Officer of Enogex Holdings |
| | 2009 - Present: | Chief Financial Officer of Enogex LLC |
| | 2008 - 2009: | Senior Vice President - Investor Relations and Financial Planning of Duke Energy (electric utility) |
| E. Keith Mitchell | 2011 - Present: | President and Chief Operating Officer of Enogex Holdings; President of Enogex LLC |
| | 2008 - 2011: | Senior Vice President and Chief Operating Officer of Enogex LLC |
| | 2008: | Senior Vice President and Chief Operating Officer of Enogex Inc. |
| Stephen E. Merrill | 2011 - Present: | Chief Operating Officer of Enogex LLC |
| | 2009 - 2011: | Vice President - Human Resources of OGE Energy Corp. and OG&E |
| | 2008 - 2009: | Vice President and Chief Financial Officer of Enogex LLC |
| | 2008: | Vice President and Chief Financial Officer of Enogex Inc. |
| William J. Bullard | 2010 - Present: | Assistant General Counsel of OGE Energy Corp.; General Counsel of OG&E |
| | 2008 - 2010: | Assistant General Counsel of OGE Energy Corp. and OG&E |
| Scott Forbes | 2008 - Present: | Controller and Chief Accounting Officer of OGE Energy Corp. and OG&E |
| | 2008 - 2009: | Interim Chief Financial Officer of OGE Energy Corp. and OG&E |
| Patricia D. Horn | 2012 - Present: | Vice President - Governance, Environmental and Corporate Secretary of OGE Energy Corp. and OG&E; Secretary of Enogex Holdings; Corporate Secretary of Enogex LLC |
| | 2010 - 2012: | Vice President - Governance, Environmental, Health & Safety; Corporate Secretary of OGE Energy Corp. and OG&E; Secretary of Enogex Holdings; Corporate Secretary of Enogex LLC |
| | 2008 - 2010: | Vice President - Legal, Regulatory, Environmental Health & Safety, General Counsel and Secretary of Enogex LLC |
| | 2008 - 2010: | Assistant General Counsel of OGE Energy Corp. |
| | 2008: | Vice President - Legal, Regulatory, Environmental Health & Safety, General Counsel and Secretary of Enogex Inc. |
| Gary D. Huneryager | 2008 - Present: | Vice President - Internal Audits of OGE Energy Corp. and OG&E |
| Jesse B. Langston | 2011 - Present: | Vice President - Retail Energy of OG&E |
| | 2008 - 2011: | Vice President - Utility Commercial Operations of OG&E |
| Jean C. Leger, Jr. | 2008 - Present: | Vice President - Utility Operations of OG&E |
| | 2008: | Vice President of Operations of Enogex Inc. |
| Cristina F. McQuistion | 2013 - Present: | Vice President - Strategic Planning, Performance Improvement and Chief Information Officer of OGE Energy Corp. and OG&E |
| | 2011 - 2013: | Vice President - Strategy and Performance Improvement of OGE Energy Corp. and OG&E |
| | 2008 - 2011: | Vice President - Process and Performance Improvement of OGE Energy Corp. and OG&E |
| | 2008: | Executive Vice President and General Manager Point of Sale Systems of Teleflora (floral industry and software services to floral industry company) |

| Name | | Business Experience |
|---|---|---|
| Max J. Myers | 2009 - Present: | Treasurer of OGE Energy Corp. and OG&E |
| | 2010 - Present: | Treasurer of Enogex Holdings |
| | 2008 - 2009: | Managing Director of Corporate Development and Finance of OGE Energy Corp. and OG&E |
| | 2008: | Manager of Corporate Development of OGE Energy Corp. and OG&E |
| Jerry A. Peace | 2008 - Present: | Chief Risk Officer of OGE Energy Corp. and OG&E |
| | 2008: | Chief Risk Officer and Compliance Officer of OGE Energy Corp. and OG&E |
| Paul L. Renfrow | 2012 - Present | Vice President - Public Affairs, Human Resources and Health & Safety of OGE Energy Corp. and OG&E |
| | 2011 - 2012: | Vice President - Public Affairs and Human Resources of OGE Energy Corp. and OG&E |
| | 2008 - 2011: | Vice President - Public Affairs of OGE Energy Corp. and OG&E |

**ACCESS TO SECURITIES AND EXCHANGE COMMISSION FILINGS**

The Company's web site address is *www.oge.com*. Through the Company's website under the heading "Investor Relations," "SEC Filings," the Company makes available, free of charge, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission. Our Internet website and the information contained therein or connected thereto are not intended to be incorporated into this Form 10-K and should not be considered a part of this Form 10-K.

**Item 1A. Risk Factors.**

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

**REGULATORY RISKS**

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

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

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

OG&E is unable to predict the impact on its operating results from the future regulatory activities of any of the agencies that regulate OG&E. Changes in regulations or the imposition of additional regulations could have an adverse impact on OG&E's results of operations.

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

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

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

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

We are subject to extensive Federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife conservation, natural resources and health and safety that could, among other things, restrict or limit the output of certain facilities or the use of certain fuels required for the production of electricity and/or require additional pollution control equipment and otherwise increase costs. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future. As discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations", in 2011, the EPA accepted a portion of the Oklahoma SIP for regional haze, which requires the installation of low NOX burners on OG&E's affected units within five years at a cost of approximately $95 million. The EPA rejected Oklahoma's SO2 BART determination with respect to the four affected coal-fired units at the Sooner and Muskogee generating stations and issued a FIP in its place. The SO2 emissions standards in the EPA's FIP could require the installation of Dry Scrubbers or fuel switching. OG&E estimates that installing such Dry Scrubbers could cost more than $1.0 billion. OG&E, the state of Oklahoma and other parties, filed an appeal to challenge this determination, which has delayed the implementation of the regional haze rule in Oklahoma. Neither the outcome of the appeal nor the timing of any required expenditures for pollution control equipment can be predicted with any certainty at this time.

In response to recent regulatory and judicial decisions, emissions of greenhouse gases including, most significantly, carbon dioxide could be restricted in the future as a result of Federal or state legal requirements or litigation relating to greenhouse gas emissions. If mandatory reductions of carbon dioxide and other greenhouse gases are required in the future, 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.

There is inherent risk of the incurrence of environmental costs and liabilities in our operations due to our handling of natural gas, air emissions related to our operations and historical industry operations and waste disposal practices. These activities are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way it can handle or dispose of their wastes or requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators. OG&E and Enogex may be unable to recover these costs from insurance. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary.

For a further discussion of environmental matters that may affect the Company, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations."

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

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

Our jurisdictions have fuel clauses that permit us to recover fuel costs through rates without a general rate case. While prudent capital investment and variable fuel costs each generally warrant recovery, in practical terms our regulators could limit the amount or timing of increased costs that we would recover through higher rates. Any such limitation could adversely affect our results of operations and financial position.

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

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

OG&E currently owns and operates transmission and generation facilities as part of a vertically integrated utility. OG&E is a member of the SPP regional transmission organization and has transferred operational authority (but not ownership) of OG&E's transmission facilities to the SPP. The SPP implemented a regional energy imbalance service market on February 1, 2007. OG&E participates in the SPP energy imbalance service market to aid in the optimization of its physical assets to serve OG&E's customers. OG&E has not participated in the SPP energy imbalance service market for any speculative trading activities. The SPP purchases and sales are not allocated to individual customers. OG&E records the hourly sales to the SPP at market rates in Operating Revenues and the hourly purchases from the SPP at market rates in Cost of Goods Sold in its Consolidated Financial Statements. OG&E's revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operation and regulation by the FERC or the SPP, including the forthcoming SPP integrated marketplace, which is scheduled to begin operation in March 2014.

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

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

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

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

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

The transportation rates charged by Enogex for transporting natural gas in interstate commerce are subject to the jurisdiction of the FERC under Section 311 of the Natural Gas Policy Act. Rates to provide such service must be "fair and equitable" under the Natural Gas Policy Act and are subject to review and approval by the FERC at least once every five years (previously a triennial requirement). See Note 17 of Notes to Consolidated Financial Statements for a discussion of Enogex's FERC Section 311 rate case. There can be no assurance that the FERC will approve Enogex's requested rates.

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

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

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

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

- identify potential threats to the public or environment, including "high consequence areas" on covered pipeline segments where a leak or rupture could do the most harm;
- develop a baseline plan to prioritize the assessment of a covered pipeline segment;
- gather data and identify and characterize applicable threats that could impact a covered pipeline segment;
- discover, evaluate and remediate problems in accordance with the program requirements;
- continuously improve all elements of the integrity program;
- continuously perform preventative and mitigation actions;
- maintain a quality assurance process and management-of-change process; and
- establish a communication plan that addresses safety concerns raised by the U.S. Department of Transportation and state agencies, including the periodic submission of performance documents to the U.S. Department of Transportation.

In 2012, Enogex incurred $13.7 million of capital expenditures and operating costs for pipeline integrity management. Enogex currently estimates that it will incur capital expenditures and operating costs of between $100 million and $160 million from 2013 to 2017 in connection with pipeline integrity management. The estimated capital expenditures and operating costs include Enogex's estimates for the assessment, remediation and prevention or other mitigation that may be determined to be necessary. At this time, Enogex cannot predict the ultimate costs of its integrity management program and compliance with this regulation because those costs will depend on the number and extent of any repairs found to be necessary. Enogex will continue to assess, remediate and maintain the integrity of its pipelines. The results of these activities could cause Enogex to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

On December 13, 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which the President signed into law on January 3, 2012. Among other things, the law requires additional verification of pipeline infrastructure records by Enogex and other intrastate and interstate pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. Where records are inadequate to confirm the maximum allowable operating pressure, the PHMSA will require the operator to re-confirm the maximum allowable operating pressure, a process that could cause temporary or permanent limitations on throughput for affected pipelines. This law required PHMSA to direct pipeline operators to verify the maximum allowable operating pressure of their pipelines by July 3, 2012, and to submit documentation to PHMSA by July 3, 2013. This law also raises the maximum penalty for violating pipeline safety rules to $0.2 million per violation per day up to $2.0 million for a related series of violations. For further information regarding this Act and potential regulations, see Note 16 of Notes to Consolidated Financial Statements. At this time, the Company is not able to estimate the capital, operating or other costs that may be required to comply with this law and any related PHMSA regulations that may be promulgated, but such costs could be significant.

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

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

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

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

In compliance with the Energy Policy Act of 2005, the FERC approved the North American Electric Reliability Corporation as the national energy reliability organization. The North American Electric Reliability Corporation is responsible for the development and enforcement of mandatory reliability and cyber security standards for the wholesale electric power system. OG&E's plan is to comply with all applicable standards and to expediently correct a violation should it occur. The North American Electric Reliability Corporation has authority to assess penalties up to $1.0 million per day per violation for noncompliance. In order to comply with new or updated security regulations, we may be required to make changes to our current operations which could also result in additional expenses. OG&E is subject to a North American Electric Reliability Corporation compliance audit every three years as well as periodic spot check audits and cannot predict the outcome of those audits.

## OPERATIONAL RISKS

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

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

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

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

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

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

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

Our operations are affected by local, national and worldwide economic conditions. The consequences of a prolonged recession could include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity could result in a decline in energy consumption, which could adversely affect our revenues and future growth. Instability in the financial markets, as a result of recession or otherwise, also could affect the cost of capital and our ability to raise capital. Economic conditions may also impact the valuation of certain long-lived or intangible assets, including goodwill, that are subject to impairment testing, potentially resulting in impairment charges, which could have a material adverse impact on our results of operations.

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

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

***We are subject to financial risks associated with climate change.***

Climate change creates financial risk. Potential regulation associated with climate change legislation could pose financial risks to the Company. In addition, to the extent that any climate change adversely affects the national or regional economic health through increased rates caused by the inclusion of additional regulatory imposed costs (carbon dioxide taxes or costs associated with additional regulatory requirements), the Company may be adversely impacted. A declining economy could adversely impact the overall financial health of the Company because of lack of load growth and decreased sales opportunities. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

***We are subject to cyber security risks and increased reliance on processes automated by technology.***

In the regular course of our businesses, we handle a range of sensitive security and customer information. We are subject to laws and rules issued by different agencies concerning safeguarding and maintaining the confidentiality of this information. A security breach of our information systems such as theft or inappropriate release of certain types of information, including confidential customer information or system operating information, could have a material adverse impact on our consolidated financial position, results of operations and cash flows.

OG&E and Enogex operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite implementation of security measures, the technology systems are vulnerable to disability, failures or unauthorized access. Such failures or breaches of the systems could impact the reliability of OG&E's generation, transmission and distribution systems (including smart grid) and Enogex's transportation systems which may result in a loss of service to customers and also subject OG&E and Enogex to financial harm due to the significant expense to repair security breaches or system damage. The implementation of OG&E's smart grid program further increases potential risks associated with cyber security attacks. If the technology systems were to fail or be breached and not recovered in a timely way, critical business functions could be impaired and sensitive confidential data could be compromised, which could have a material adverse impact on its consolidated financial position, results of operations and cash flows.

Our security procedures, which include among others, virus protection software, cyber security and our business continuity planning, including disaster recovery policies and back-up systems, may not be adequate or implemented properly to fully address the adverse affect of cyber security attacks on our systems, which could adversely impact our operations.

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

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

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

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

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

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

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

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

Enogex's keep-whole natural gas processing arrangements, which constituted 21 percent of its gross margin and accounted for 21 percent of its natural gas processed volumes in 2012, expose it to fluctuations in the pricing spreads between NGLs prices and natural gas prices. Keep-whole processing arrangements generally require a processor of natural gas to keep its shippers whole on a British thermal unit basis by replacing the British thermal units of the NGLs extracted from the production stream with British thermal units of natural gas. Therefore, if natural gas prices increase and NGLs prices do not increase by a corresponding amount, the processor has to replace the British thermal units of natural gas at higher prices and processing margins are negatively affected.

Enogex's percent-of-proceeds and percent-of-liquids natural gas processing agreements constituted two percent and five percent, respectively, of its gross margin and accounted for 16 percent and 28 percent, respectively, of its natural gas processed volumes in 2012. Under these arrangements, Enogex generally gathers raw natural gas from producers at the wellhead, transports the gas through its gathering system, processes the gas and sells the processed gas and/or NGLs at prices based on published index prices. The price paid to producers is based on an agreed percentage of the proceeds of the sale of processed natural gas, NGLs or both or the expected proceeds based on an index price. Enogex refers to contracts in which it shares in specified percentages of the proceeds from the sale of natural gas and NGLs as percent-of-proceeds arrangements and in which it receives proceeds from the sale of NGLs or the NGLs themselves as compensation for its processing services as percent-of-liquids arrangements. These arrangements expose Enogex to risks associated with the price of natural gas and NGLs.

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

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

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

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

All of Enogex's businesses are dependent on the continued availability of natural gas production. Enogex does not have control over the level of drilling activity in the areas of its operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. The primary factor that impacts drilling decisions is natural gas prices. Natural gas prices are currently around $3.21 per MMBtu. A decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by Enogex's gathering, processing and transportation facilities, which would lead to reduced utilization of these assets. Other factors that impact production decisions include producers' capital budgets, access to credit, the ability of producers to obtain necessary drilling and other governmental permits, costs of steel and other commodities, geological considerations, demand for hydrocarbons, the level and composition of reserves, other production and development costs and regulatory changes. In particular, certain states have adopted or are considering, and Congress is considering, adopting regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In the event Federal, state, local or municipal legal restrictions are adopted in the areas where Enogex operates, there may be a delay or curtailment in drilling activities. Because of these factors, even if new natural gas reserves are discovered in areas served by Enogex's assets, producers may choose not to develop those reserves.

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

The Company is exposed to changes in commodity prices in its operations. The Company has used forward physical contracts, commodity price swap contracts and commodity price option features to manage the Company's commodity price risk exposures in the past.

From time to time, Enogex has instituted a hedging program that was intended to reduce the commodity price risk associated with Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing operations and natural gas transportation and storage operations (operational gas hedges). Management will continue to evaluate whether to enter into any new hedging arrangements and there can be no assurance that Enogex will enter into any new hedging arrangements. To the extent Enogex hedges its commodity price and interest rate exposures, Enogex may forego the benefits that otherwise would be experienced if commodity prices or interest rates were to change in Enogex's favor. In addition, even though management monitors Enogex's hedging activities, these activities can result in substantial losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect or ineffective, or the hedging policies and procedures are not followed or do not work as planned.

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

Enogex relies on certain key natural gas producer customers for a significant portion of its natural gas and NGLs supply. Enogex's key natural gas producer customers in 2012 included Chesapeake Energy Marketing Inc., Apache Corporation and Devon Energy Production Company, L.P. In 2012, these customers accounted for 19.6 percent, 17.8 percent and 10.6 percent, respectively, of Enogex's gathering and processing volumes. In 2012, Enogex's top 10 natural gas producer customers accounted for 73.0 percent of Enogex's gathering and processing volumes. The loss of the natural gas and NGLs volumes supplied by these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could have a material adverse effect on Enogex's consolidated financial position, results of operations and cash flows.

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

Enogex provides firm intrastate transportation and storage services to several customers on its system. Enogex's major transportation customers are OG&E and PSO, the second largest electric utility in Oklahoma. As part of the no-notice load following contract with OG&E, Enogex provides natural gas storage services for OG&E. Enogex provides gas transmission delivery services to all of PSO's natural gas-fired electric generation facilities in Oklahoma under a firm intrastate transportation contract. In 2012, 2011 and 2010, revenues from Enogex's firm intrastate natural gas transportation and storage contracts were $131.5 million, $130.7 million and $116.6 million, respectively, of which $47.5 million in each year was attributed to OG&E and $15.3 million in each year was attributed to PSO. The PSO contract and the OG&E contract provide for a monthly demand charge plus variable transportation charges including fuel. The stated term of the PSO contract expired January 1, 2013, but the contract remains in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 180 days prior to the commencement of the next succeeding annual period. Because neither party provided notice of termination 180 days prior to January 1, 2013, the PSO contract will remain in effect at least through January 1, 2014. The stated term of the OG&E contract expired April 30, 2009, but the contract remains in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 180 days prior to the commencement of the next succeeding annual period. Because neither party provided notice of termination 180 days prior to May 1, 2013, the OG&E contract will remain in effect at least through April 30, 2014. The loss of all or even a portion of the intrastate transportation and storage services for either of these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could have a material adverse effect on Enogex's consolidated financial position, results of operations and cash flows.

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

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

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

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

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

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

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

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

***Our investment agreement with the ArcLight group involves risks and uncertainties.***

As part of our investment agreement with the ArcLight group, we are entitled to designate three directors, and the ArcLight group was initially entitled to designate one director of Enogex Holdings. The investment agreement provides the ArcLight group the opportunity to increase its ownership interest by providing equity funding for capital expenditures associated with Enogex's business plan. As its ownership position increases, the ArcLight group will be entitled to increasing board representation. At December 31, 2012, OGE Energy indirectly owns a 79.9 percent membership interest in Enogex Holdings. The ArcLight group will also be entitled, at various ownership thresholds, to certain special board approval rights with respect to certain significant actions taken by Enogex Holdings, as well as to appoint additional directors for Enogex Holdings.

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

**FINANCIAL RISKS**

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

We have a Pension Plan that covers a significant amount of our employees hired before December 1, 2009. We also have defined benefit postretirement plans that cover a significant amount of our employees hired prior to February 1, 2000. Assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions with respect to the defined benefit retirement and postretirement plans have a significant impact on our results of operations and funding requirements. Based on our assumptions at December 31, 2012, we expect to continue to make future contributions to maintain required funding levels. It has been our practice in the past to also make voluntary contributions to maintain more prudent funding levels than minimally required. We may continue to make voluntary contributions in the future. These amounts are estimates and may change based on actual stock market performance, changes in interest rates and any changes in governmental regulations.

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

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

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

Workforce demographic issues challenge employers nationwide and are of particular concern to the electric utility and natural gas pipeline industry. The median age of utility and natural gas pipeline workers is significantly higher than the national average. Over the next three years, 29 percent of our current employees will be eligible to retire with full pension benefits. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business.

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

We are a holding company and thus our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and our ability to pay our dividends and service our indebtedness depends upon the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends. At December 31, 2012, the Company and its subsidiaries had outstanding indebtedness and other liabilities of $6.8 billion. Our subsidiaries are separate legal entities that have no obligation to pay any amounts due on our indebtedness or to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary's ability to pay dividends to us depends on any statutory and contractual restrictions that may be applicable to such subsidiary, which may include requirements to maintain minimum levels of working capital and other assets. Claims of creditors, including general creditors, of our subsidiaries on the assets of these subsidiaries will have priority over our claims generally (except to the extent that we may be a creditor of the subsidiaries and our claims are recognized) and claims by our shareowners.

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

***Certain provisions in our charter documents have anti-takeover effects.***

Certain provisions of our certificate of incorporation and bylaws, as well as the Oklahoma corporations statute, may have the effect of delaying, deferring or preventing a change in control of the Company. Such provisions, including those regulating the nomination of directors, limiting who may call special stockholders' meetings and eliminating stockholder action by written consent, together with the possible issuance of preferred stock of the Company without stockholder approval, may make it more difficult for other persons, without the approval of our board of directors, to make a tender offer or otherwise acquire substantial amounts of our common stock or to launch other takeover attempts that a stockholder might consider to be in such stockholder's best interest.

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

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

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

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

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

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

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

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

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

**Item 1B. Unresolved Staff Comments.**

None.

**Item 2. Properties.**

***OG&E***

OG&E owns and operates an interconnected electric generation, transmission and distribution system, located in Oklahoma and western Arkansas, which included 10 generating stations with an aggregate capability of 6,807 MWs at December 31, 2012. The following tables set forth information with respect to OG&E's electric generating facilities, all of which are located in Oklahoma.

| Station & Unit | | Year Installed | Unit Design Type | Fuel Capability | Unit Run Type | 2012 Capacity Factor (A) | Unit Capability (MW) | Station Capability (MW) |
|---|---|---|---|---|---|---|---|---|
| Seminole | 1 | 1971 | Steam-Turbine | Gas | Base Load | 24.8% | 465 | |
| | 1GT | 1971 | Combustion-Turbine | Gas | Peaking | 0.2% (B) | 16 | |
| | 2 | 1973 | Steam-Turbine | Gas | Base Load | 18.9% | 490 | |
| | 3 | 1975 | Steam-Turbine | Gas/Oil | Base Load | 26.3% | 477 | 1,448 |
| Muskogee | 4 | 1977 | Steam-Turbine | Coal | Base Load | 57.8% | 489 | |
| | 5 | 1978 | Steam-Turbine | Coal | Base Load | 62.5% | 509 | |
| | 6 | 1984 | Steam-Turbine | Coal | Base Load | 52.7% | 508 | 1,506 |
| Sooner | 1 | 1979 | Steam-Turbine | Coal | Base Load | 61.2% | 516 | |
| | 2 | 1980 | Steam-Turbine | Coal | Base Load | 62.7% | 520 | 1,036 |
| Horseshoe Lake | 6 | 1958 | Steam-Turbine | Gas/Oil | Base Load | 17.7% | 171 | |
| | 7 | 1963 | Combined Cycle | Gas/Oil | Base Load | 15.5% | 222 | |
| | 8 | 1969 | Steam-Turbine | Gas | Base Load | 12.3% | 399 | |
| | 9 | 2000 | Combustion-Turbine | Gas | Peaking | 3.7% (B) | 45 | |
| | 10 | 2000 | Combustion-Turbine | Gas | Peaking | 3.4% (B) | 45 | 882 |
| Redbud (C) | 1 | 2003 | Combined Cycle | Gas | Base Load | 62.7% | 148 | |
| | 2 | 2003 | Combined Cycle | Gas | Base Load | 65.4% | 149 | |
| | 3 | 2003 | Combined Cycle | Gas | Base Load | 70.7% | 146 | |
| | 4 | 2003 | Combined Cycle | Gas | Base Load | 47.1% | 151 | 594 |
| Mustang | 1 | 1950 | Steam-Turbine | Gas | Peaking | 3.2% (B) | 52 | |
| | 2 | 1951 | Steam-Turbine | Gas | Peaking | 4.6% (B) | 52 | |
| | 3 | 1955 | Steam-Turbine | Gas | Base Load | 16.3% | 117 | |
| | 4 | 1959 | Steam-Turbine | Gas | Base Load | 13.8% | 250 | |
| | 5A | 1971 | Combustion-Turbine | Gas/Jet Fuel | Peaking | 0.7% (B) | 34 | |
| | 5B | 1971 | Combustion-Turbine | Gas/Jet Fuel | Peaking | 0.8% (B) | 33 | 538 |
| McClain (D) | 1 | 2001 | Combined Cycle | Gas | Base Load | 85.8% | 354 | 354 |
| Total Generating Capability (all stations, excluding wind stations) (E) | | | | | | | | 6,358 |

| Station | Year Installed | Location | Number of Units | Fuel Capability | 2012 Capacity Factor (A) | Unit Capability (MW) | Station Capability (MW) |
|---|---|---|---|---|---|---|---|
| Crossroads | 2011 | Woodward, OK | 99 | Wind | 45.8% | 2.3 | 227.5 |
| Centennial | 2007 | Woodward, OK | 80 | Wind | 33.2% | 1.5 | 120 |
| OU Spirit | 2009 | Woodward, OK | 44 | Wind | 36.9% | 2.3 | 101 |
| Total Generating Capability (wind stations) | | | | | | | 448.5 |

(A) 2012 Capacity Factor = 2012 Net Actual Generation / (2012 Net Maximum Capacity (Nameplate Rating in MWs) x Period Hours (8,760 Hours)).
(B) Peaking units are used when additional short-term capacity is required.
(C) Represents OG&E's 51 percent ownership interest in the Redbud Plant.
(D) Represents OG&E's 77 percent ownership interest in the McClain Plant.
(E) In December 2012, the Enid and Woodward generating stations were retired.

At December 31, 2012, OG&E's transmission system included: (i) 51 substations with a total capacity of 11.9 million kilovolt-amps and 4,426 structure miles of lines in Oklahoma and (ii) seven substations with a total capacity of 2.4 million kilovolt-amps and 279 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 353 substations with a total capacity of 9.4 million kilovolt-amps, 29,103 structure miles of overhead lines, 2,110 miles of underground conduit and 10,580 miles of underground conductors in Oklahoma and (ii) 38 substations with a total capacity of 1.1 million kilovolt-amps, 2,778 structure miles of overhead lines, 219 miles of underground conduit and 700 miles of underground conductors in Arkansas.

OG&E owns 140,133 square feet of office space at its executive offices at 321 North Harvey, Oklahoma City, Oklahoma 73102. In addition to its executive offices, OG&E owns numerous facilities throughout its service territory that support its operations. These facilities include, but are not limited to, service centers, fleet and equipment service facilities, operation support and other properties.

***Enogex***

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

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

At December 31, 2012, Enogex and its subsidiaries owned: (i) approximately 6,640 miles of intrastate natural gas gathering pipelines in Oklahoma and Texas; (ii) approximately 2,284 miles of intrastate natural gas transportation pipelines in Oklahoma; (iii) two underground natural gas storage facilities in Oklahoma operating at a combined working gas level of 24 billion cubic feet with 650 MMcf/d of maximum withdrawal capacity and 650 MMcf/d of injection capacity; (iv) 660,655 horsepower of owned compression and (v) nine operating natural gas processing plants, with a current total inlet capacity of 1,305 MMcf/d, all located in Oklahoma. The following table sets forth information with respect to Enogex's active natural gas processing plants:

| Processing Plant | Year Installed | Type of Plant | Fuel Capability | 2012 Average Daily Inlet Volumes (MMcf/d) | Inlet Capacity (MMcf/d) |
|---|---|---|---|---|---|
| Calumet (A) (B) | 1969 | Lean Oil | Gas/Electric | 68 | 250 |
| South Canadian (A) | 2011 | Cryogenic | Electric | 192 | 200 |
| Wheeler (A) (C) | 2012 | Cryogenic | Electric | 155 | 200 |
| Cox City (A) | 1994 | Cryogenic | Gas/Electric | 146 | 180 |
| Thomas (A) | 1981 | Cryogenic | Gas | 117 | 135 |
| Clinton (A) | 2009 | Cryogenic | Electric | 84 | 120 |
| Roger Mills (D) | 2008 | Refrigeration | Electric | 31 | 100 |
| Canute (D) | 1996 | Cryogenic | Electric | 54 | 60 |
| Wetumka (A) | 1983 | Cryogenic | Gas/Electric | 32 | 60 |
| Total | | | | 879 | 1,305 |

(A) These processing plants are located on property that Enogex owns in fee.
(B) This processing plant will be used when additional capacity is required.
(C) This processing plant was placed into service in August 2012.
(D) These processing plants are located on easements or leased property as described above.

Enogex currently occupies 134,219 square feet of office space at its executive offices at 211 N. Robinson, Suite 900, Oklahoma City, Oklahoma 73102 under a lease that expires March 31, 2017. Although Enogex may require additional office space as its business expands, Enogex believes that its new facilities are adequate to meet its needs for the immediate future. In addition to its executive offices, Enogex owns numerous facilities throughout its service territory that support its operations. These facilities include, but are not limited to, district offices, fleet and equipment service facilities, compressor station facilities, operation support and other properties.

During the three years ended December 31, 2012, the Company's gross property, plant and equipment (excluding construction work in progress) additions were $3.3 billion and gross retirements were $415.7 million (including assets held for sale of $31.1 million). These additions were provided by cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper), long-term borrowings and permanent financings. The additions during this three-year period amounted to 29.0 percent of gross property, plant and equipment (excluding construction work in progress) at December 31, 2012.

**Item 3. Legal Proceedings.**

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. At the present time, based on currently available information, except as set forth below, under "Environmental Laws and Regulations" in Item 7 of Part II of this Form 10-K and in Notes 16 and 17 of Notes to Consolidated Financial Statements, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

1. *Patent Infringement Case.* On September 16, 2011, TransData, Inc., a Texas corporation, sued OG&E in the Western District of Oklahoma, accusing OG&E of infringing three of their U.S. patents by using OG&E's General Electric "smart" meters with Silver Spring Networks wireless modules. The complaint seeks a judgment of infringement, unspecified damages, a permanent injunction, costs and attorneys fees. OG&E was served with the complaint on September 21, 2011 and has notified both General Electric and Silver Springs Network of the lawsuit and its intent to seek indemnity from those companies for any damages that it may incur from this lawsuit. TransData, Inc. sought to consolidate its OG&E lawsuit with similar lawsuits in the Eastern District of Texas, however, on December 13, 2011, the TransData, Inc. cases were consolidated in the Western District of Oklahoma. OG&E has filed a motion for extension of time to answer the complaint. On December 30, 2011, OG&E and General Electric agreed to terms for General Electric to provide OG&E with an unqualified defense in the matter and to indemnify OG&E for costs, expenses and damages awarded against OG&E subject to a reservation of rights. While the Company cannot predict the outcome of this lawsuit at this time, the Company intends to vigorously defend this action and believes that its ultimate resolution will not be material to the Company's consolidated financial position, results of operations or cash flows.

**Item 4. Mine Safety Disclosures.**

Not Applicable.

**PART II**

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

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

| 2013 | Dividend Paid | Price High | Price Low |
|---|---|---|---|
| First Quarter (through February 22) | $ 0.4175 | $ 60.00 | $ 56.12 |
| 2012 | | | |
| First Quarter | $ 0.3925 | $ 57.54 | $ 51.24 |
| Second Quarter | 0.3925 | 55.31 | 50.23 |
| Third Quarter | 0.3925 | 56.49 | 50.60 |
| Fourth Quarter | 0.3925 | 60.21 | 54.36 |
| 2011 | | | |
| First Quarter | $ 0.3750 | $ 50.61 | $ 44.69 |
| Second Quarter | 0.3750 | 53.50 | 47.64 |
| Third Quarter | 0.3750 | 52.15 | 40.56 |
| Fourth Quarter | 0.3750 | 57.17 | 45.70 |

At the Company's November 2012 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 $0.4175 per share from $0.3925 per share effective with the Company's first quarter 2013 dividend.

The number of record holders of the Company's Common Stock at December 31, 2012, was 18,905. The book value of the Company's Common Stock at December 31, 2012 was $28.02.

**Dividend Restrictions**

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

**Issuer Purchases of Equity Securities**

The following table contains information about the Company's purchases of its common stock during the fourth quarter of 2012.

| Period | Total Number of Shares Purchased | | Average Price Paid Per Share | Total Number of Shares Purchased as Part of Publicly Announced Plan | Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan |
|---|---|---|---|---|---|
| 10/1/12 – 10/31/12 | — | | $ — | N/A | N/A |
| 11/1/12 – 11/30/12 | 60,000 | (A) | $ 55.41 | 60,000 | N/A |
| 12/1/12 – 12/31/12 | 357 | (B) | $ 57.04 | N/A | N/A |

(A) In November 2012, the Company purchased 60,000 shares of its common stock at an average cost of $55.41 per share on the open market. These shares will be used to satisfy Enogex's portion of the Company's obligation to deliver shares of common stock related to long-term incentive payouts of earned performance units in 2013.

(B) These shares of restricted stock were returned to the Company to satisfy tax liabilities.

N/A – not applicable

**Item 6. Selected Financial Data**

**HISTORICAL DATA**

| Year ended December 31 | **2012** | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| SELECTED FINANCIAL DATA | | | | | |
| *(In millions, except per share data)* | | | | | |
| | | | | | |
| **Results of Operations Data:** | | | | | |
| Operating revenues | **$ 3,671.2** | $ 3,915.9 | $ 3,716.9 | $ 2,869.7 | $ 4,070.7 |
| Cost of goods sold | **1,918.7** | 2,277.9 | 2,187.4 | 1,557.7 | 2,818.0 |
| Gross margin on revenues | **1,752.5** | 1,638.0 | 1,529.5 | 1,312.0 | 1,252.7 |
| Operating expenses | **1,075.6** | 991.3 | 935.6 | 820.1 | 790.6 |
| Operating income | **676.9** | 646.7 | 593.9 | 491.9 | 462.1 |
| Interest income | **0.6** | 0.5 | — | 1.4 | 6.7 |
| Allowance for equity funds used during construction | **6.2** | 20.4 | 11.4 | 15.1 | — |
| Other income | **17.0** | 19.3 | 13.7 | 27.5 | 15.4 |
| Other expense | **16.5** | 21.7 | 17.9 | 16.3 | 25.6 |
| Interest expense | **164.1** | 140.9 | 139.7 | 137.4 | 120.0 |
| Income tax expense | **135.1** | 160.7 | 161.0 | 121.1 | 101.2 |
| Net income | **385.0** | 363.6 | 300.4 | 261.1 | 237.4 |
| Less: Net income attributable to noncontrolling interests | **30.0** | 20.7 | 5.1 | 2.8 | 6.0 |
| Net income attributable to OGE Energy | **$ 355.0** | $ 342.9 | $ 295.3 | $ 258.3 | $ 231.4 |
| Basic earnings per average common share attributable to OGE Energy common shareholders | **$ 3.60** | $ 3.50 | $ 3.03 | $ 2.68 | $ 2.50 |
| Diluted earnings per average common share attributable to OGE Energy common shareholders | **$ 3.58** | $ 3.45 | $ 2.99 | $ 2.66 | $ 2.49 |
| Dividends declared per common share | **$ 1.5950** | $ 1.5175 | $ 1.4625 | $ 1.4275 | $ 1.3975 |
| **Balance Sheet Data (at period end):** | | | | | |
| Property, plant and equipment, net | **$ 8,344.8** | $ 7,474.0 | $ 6,464.4 | $ 5,911.6 | $ 5,249.8 |
| Total assets | **$ 9,922.2** | $ 8,906.0 | $ 7,669.1 | $ 7,266.7 | $ 6,518.5 |
| Long-term debt | **$ 2,848.6** | $ 2,737.1 | $ 2,362.9 | $ 2,088.9 | $ 2,161.8 |
| Total stockholders' equity | **$ 3,072.4** | $ 2,819.3 | $ 2,400.0 | $ 2,060.8 | $ 1,914.0 |
| **Capitalization Ratios (A)** | | | | | |
| Stockholders' equity | **51.9%** | 50.7% | 50.4% | 46.4% | 47.0% |
| Long-term debt | **48.1%** | 49.3% | 49.6% | 53.6% | 53.0% |
| **Ratio of Earnings to Fixed Charges (B)** | | | | | |
| Ratio of earnings to fixed charges | **3.94** | 4.12 | 4.02 | 3.38 | 3.55 |

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

(B) For purposes of computing the ratio of earnings to fixed charges, (i) earnings consist of pre-tax income plus fixed charges, less allowance for borrowed funds used during construction and other capitalized interest and (ii) fixed charges consist of interest on long-term debt, related amortization, interest on short-term borrowings and a calculated portion of rents considered to be interest.

## Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

### Introduction

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through three business segments: (i) electric utility, (ii) natural gas transportation and storage and (iii) natural gas gathering and processing.

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

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. This new organization is intended to facilitate the execution of Enogex's strategy through an enhanced focus on asset optimization and active management of its growing natural gas, NGLs and condensate positions. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. Enogex's operations are now organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. At December 31, 2012, OGE Energy indirectly owns a 79.9 percent membership interest in Enogex Holdings, which in turn owns all of the membership interests in Enogex LLC.

### Overview

#### *Company Strategy*

The Company's mission is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customers' needs for energy and related services focusing on safety, efficiency, reliability, customer service and risk management. The Company's corporate strategy is to continue to maintain its existing business mix and diversified asset position of its regulated electric utility business and unregulated natural gas midstream business while providing competitive energy products and services to customers primarily in the south central United States as well as seeking growth opportunities in both businesses.

OG&E is focused on increased investment to preserve system reliability and meet load growth by adding and maintaining infrastructure equipment and replacing aging transmission and distribution systems. OG&E expects to maintain a diverse generation portfolio while remaining environmentally responsible. OG&E is focused on maintaining strong regulatory and legislative relationships for the long-term benefit of its customers. In an effort to encourage more efficient use of electricity, OG&E is also providing energy management solutions to its customers through the Smart Grid program that utilizes newer technology to improve operational and environmental performance as well as allow customers to monitor and manage their energy usage, which should help reduce demand during critical peak times, resulting in lower capacity requirements. If these initiatives are successful, OG&E believes it may be able to defer the construction or acquisition of any incremental fossil fuel generation capacity until 2020. The Smart Grid program also provides benefits to OG&E, including more efficient use of its resources and access to increased information about customer usage, which should enable OG&E to have better distribution system planning data, better response to customer usage questions and faster detection and restoration of system outages. As the Smart Grid platform matures, OG&E anticipates providing new products and services to its customers. In addition, OG&E is also pursuing additional transmission-related opportunities within the SPP.

Enogex's business plan entails growing its businesses and providing attractive financial returns through efficient operations and effective commercial management of its assets. Enogex also plans to capture growth opportunities through expansion projects, increased utilization of existing assets and through acquisitions (including joint ventures) in and around its footprint and attracting new customers. In addition, Enogex is seeking to geographically diversify its gathering, processing and transportation businesses principally by expanding into other areas that are complementary with the Company's capabilities. Enogex expects to accomplish this diversification by undertaking organic growth projects and through acquisitions.

Additionally, the Company wants to achieve a premium valuation of its businesses relative to its peers, grow earnings per share with a stable earnings pattern, create a high performance culture and achieve desired outcomes with target stakeholders.

The Company's financial objectives include a long-term annual earnings growth rate of five to seven percent on a weather-normalized basis, maintaining a strong credit rating as well as increasing the dividend to meet the Company's dividend payout objectives. The Company's target payout ratio is to pay out dividends no more than 60 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. The Company believes it can accomplish these financial objectives by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and maintaining strong regulatory and legislative relationships.

***Summary of Operating Results***

**2012 compared to 2011.** Net income attributable to OGE Energy was $355.0 million, or $3.58 per diluted share, in 2012 as compared to $342.9 million, or $3.45 per diluted share, in 2011. The increase in net income attributable to OGE Energy of $12.1 million, or 3.5 percent, or $0.13 per diluted share, in 2012 as compared to 2011 was primarily due to:

- an increase in net income at OG&E of $17.0 million, or 6.5 percent, or $0.18 per diluted share of the Company's common stock, primarily due to a higher gross margin and lower income tax expense. The higher gross margin was primarily due to increased recovery of investments and increased transmission revenue partially offset by milder weather in OG&E's service territory. These increases were partially offset by higher other operation and maintenance expense, higher depreciation and amortization expense, lower allowance for equity funds used during construction and higher interest expense;
- a decrease in net income at Enogex of $8.1 million, or 9.9 percent, or $0.08 per diluted share of the Company's common stock, primarily due to higher other operation and maintenance expense, higher depreciation and amortization expense, lower other income primarily due to the recognition of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in 2011, higher interest expense and OGE Energy's lower membership interest in Enogex Holdings. These decreases were partially offset by a higher gross margin related to (i) increased gathering rates and volumes associated with ongoing expansion projects and increased volumes from gas gathering assets acquired in November 2011 and August 2012 and (ii) increased inlet volumes partially offset by lower average natural gas and NGLs prices. Also having a positive impact on net income was a higher gain on insurance proceeds in 2012 and an impairment related to the Atoka processing plant in 2011; and
- an increase in net income at OGE Energy of $3.2 million, or $0.03 per diluted share of the Company's common stock, primarily due to higher other income due to a decrease in deferred compensation losses partially offset by higher interest expense and a lower income tax benefit in 2012.

*Non-Recurring Items.* During 2012, Enogex had an increase in net income of $4.6 million due to a gain on insurance proceeds related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant partially offset by a decrease in net income of $2.1 million related to sales taxes on the assets acquired in the gas gathering acquisitions in August 2012, as discussed in Note 3 of Notes to Consolidated Financial Statements, which Enogex does not consider to be reflective of its ongoing performance. During 2011, Enogex had an increase in net income of $2.3 million relating to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011, which Enogex does not consider to be reflective of its ongoing performance.

**2011 compared to 2010.** Net income attributable to OGE Energy was $342.9 million, or $3.45 per diluted share, in 2011 as compared to $295.3 million, or $2.99 per diluted share, in 2010. Included in net income attributable to OGE Energy in 2010 was a one-time, non-cash charge of $11.4 million, or $0.11 per diluted share, related to the elimination of the tax deduction for the Medicare Part D subsidy (as previously reported in the Company's Form 10-Q for the quarter ended March 31, 2011). The increase in net income attributable to OGE Energy of $47.6 million, or 16.1 percent, or $0.46 per diluted share, in 2011 as compared to 2010 was primarily due to:

- an increase in net income at OG&E of $47.6 million or 22.1 percent, or $0.47 per diluted share of the Company's common stock, primarily due to a higher gross margin primarily from warmer weather in OG&E's service territory partially offset by higher other operation and maintenance expense, higher interest expense and higher income tax expense. Income tax expense was higher due to higher pre-tax income which more than offset the effects of the Medicare Part D subsidy discussed above;
- a decrease in net income at Enogex of $8.9 million or 9.8 percent, or $0.09 per diluted share of the Company's common stock, primarily due to higher other operation and maintenance expense and OGE Energy's lower membership interest in Enogex Holdings partially offset by a higher gross margin primarily from higher NGLs

prices and increased gathered volumes associated with ongoing expansion projects, the recognition of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets, lower interest expense and lower income tax expense related to the Medicare Part D subsidy discussed above; and

- an increase in the net income at OGE Energy of $8.9 million or 77.4 percent or $0.08 per diluted share of the Company's common stock, primarily due to lower other operation and maintenance expense, a decrease in charitable contributions in 2011 and a higher income tax benefit related to the Medicare Part D subsidy discussed above.

*Non-Recurring Item.* During 2011, Enogex had an increase in net income of $2.3 million relating to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011, which Enogex does not consider to be reflective of its ongoing performance.

*Timing Item.* Enogex's net income in 2011 was $82.2 million, which included a loss of $2.6 million resulting from recording Enogex'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 quarter of 2012.

**Recent Developments and Regulatory Matters**

***OG&E SPP Transmission Projects***

In 2007, the SPP notified OG&E to construct 44 miles of a new 345 kilovolt transmission line originating at OG&E's existing Sooner 345 kilovolt substation and proceeding generally in a northerly direction to the Oklahoma/Kansas Stateline (referred to as the Sooner-Rose Hill project). At the Oklahoma/Kansas Stateline, the line connects to the companion line constructed in Kansas by Westar Energy. The transmission line was placed in service in April 2012. The total capital expenditures associated with this project were $45 million.

In January 2009, OG&E received notification from the SPP to begin construction on 50 miles of a new 345 kilovolt transmission line and substation upgrades at OG&E's Sunnyside substation, among other projects. In April 2009, Western Farmers Electric Cooperative assigned to OG&E the construction of 50 miles of line designated by the SPP to be built by Western Farmers Electric Cooperative. The new line extends from OG&E's Sunnyside substation near Ardmore, Oklahoma, 123.5 miles to the Hugo substation owned by Western Farmers Electric Cooperative near Hugo, Oklahoma. The transmission line was completed in April 2012. The total capital expenditures associated with this project were $157 million.

As discussed in Note 17 of Notes to Consolidated Financial Statements, the OCC approved a settlement agreement in OG&E's 2011 Oklahoma rate case filing that included an expedited procedure for recovering the costs of the two projects. On July 31, 2012, OG&E filed an application with the OCC requesting an order authorizing recovery for the two projects through the SPP transmission systems additions rider. On October 2, 2012, all parties signed a settlement agreement in this matter which stated: (i) the parties agree not to oppose requested relief sought by OG&E, (ii) OG&E will host meetings to discuss the SPP’s transmission planning process, including any future transmission projects for which OG&E has received a notice to construct from the SPP, and (iii) there will be opportunities for parties to provide input related to transmission planning studies that the SPP performs to identify future transmission projects. On October 25, 2012, the OCC issued an order approving the settlement agreement and granting OG&E cost recovery for the two projects. OG&E initiated cost recovery beginning with the first billing cycle in November 2012.

***OG&E Demand and Energy Efficiency Program Filing***

On July 2, 2012, OG&E filed an application with the OCC requesting approval of OG&E's 2013 demand portfolio, the authorization to recover the program costs, lost revenues associated with any achieved energy, demand savings and performance based incentives through the demand program rider and the recovery of costs associated with research and development investments. On July 16, 2012, OG&E filed an amended application which modified various calculations to reflect the rate of return authorized by the OCC in OG&E's 2011 rate case order and provided for consideration of a peak time rebate program. On December 20, 2012, the OCC approved a settlement with all parties in this matter. Key terms of the settlement included (i) approval of the program budgets proposed by OG&E and an additional amount of approximately $7 million over the three-year period for the energy efficiency programs, (ii) approval of OG&E’s proposed Demand Program Rider tariff, (iii) the recovery through the Demand Program Rider of the increased program costs and the net lost revenues, incentives and research and development investments requested by OG&E, with the exception of lost revenues resulting from the Integrated Volt Var Control program (automated intelligence to control voltage and power on the distribution lines) and incentives for the SmartHours® and Integrated Volt Var Control demand response programs, (iv) recovery of the program costs on a levelized basis over the three-year period, (v) consideration of implementing a peak time rebate program in 2015 and (vi) the periodic filing of additional reports. The Demand Program Rider became effective on January 1, 2013.

***OG&E Fuel Adjustment Clause Review for Calendar Year 2010***

The OCC routinely reviews the costs recovered from customers through OG&E’s fuel adjustment clause. On August 19, 2011, the OCC Staff filed an application to review OG&E’s fuel adjustment clause for calendar year 2010, including the prudence of OG&E’s electric generation, purchased power and fuel procurement costs. OG&E responded by filing direct testimony and the minimum filing review package on October 18, 2011. On September 26, 2012, the administrative law judge recommended that the OCC find that for the calendar year 2010 OG&E's generation, purchase power and fuel procurement processes and costs, including the cost of replacement power for the Sooner 2 outage, were prudent and no disallowance (as discussed below) for any of these expenses is warranted. On January 31, 2013, the OCC issued an order approving the administrative law judge's recommendation. Previously, the Oklahoma Industrial Energy Consumers recommended that the OCC disallow recovery of approximately $44 million of costs previously recovered through OG&E's fuel adjustment clause. These recommendations were based on allegations that OG&E's lower cost coal-fired generation was underutilized, that OG&E failed to aggressively pursue purchasing power at a cost lower than its marginal cost of generation and that OG&E should be found imprudent related to an unplanned outage at OG&E's Sooner 2 coal unit in November and December 2010. Previously, the OCC Staff recommended approval of OG&E's actions related to utilization of coal plants and practices related to purchasing power but recommended that OG&E refund $3 million to customers because of the Sooner 2 outage.

***Texas Panhandle Gathering Divestiture***

On January 2, 2013, Enogex and one of its five largest customers entered into new agreements, effective January 1, 2013, relating to the customer's gathering and processing volumes on the Texas portion of Enogex's system. The effects of this new arrangement are (i) a fixed fee processing agreement replaces the previous keep-whole agreement, (ii) the acreage dedicated by the customer to Enogex for gathering and processing in Texas has been increased for an extended term and (iii) the sale by Enogex of certain gas gathering assets in the Texas Panhandle portion of Enogex's system to this customer for cash proceeds of approximately $35 million. The sale of these assets was approved by the Company's and Enogex's Board of Directors in November 2012, therefore these assets were classified as held for sale on the Company's Consolidated Balance Sheet at December 31, 2012. Enogex expects to recognize a pre-tax gain of approximately $10 million in the first quarter of 2013 in its natural gas gathering and processing segment from the sale of these assets.

***Enogex Western Oklahoma / Texas Panhandle Natural Gas Gathering and Processing System Expansions***

In August 2012, Enogex completed construction of its cryogenic processing plant in Wheeler County, Texas, which added 200 MMcf/d of rich gas processing capacity to Enogex's system, and is supported by the installation of 9,400 horsepower of field compression, as well as 6,000 horsepower of inlet compression to facilitate additional flexibility in the operation of Enogex's "super-header" gathering system. The remainder of the inlet compression facilities is expected to be in service during the second quarter of 2013.

In support of significant long-term acreage dedications from its customers in the area, Enogex has expanded its gathering infrastructure in western Oklahoma and the Texas Panhandle. These expansions included the installation of 39,700 horsepower of low pressure compression and 235 miles of gathering pipe across the area, which was completed during the third quarter of 2012.

In support of significant long-term acreage dedications from its customers in the area, Enogex is expanding its gathering infrastructure in southern Oklahoma. The initial phase of these expansions include the installation of approximately 20,000 horsepower of compression and approximately 100 miles of gathering pipeline, which are expected to be in service by the end of the first quarter of 2013. The remainder of the expansion includes the installation of approximately 50,000 horsepower of compression and approximately 300 miles of gathering pipeline, which are expected to be in service by the end of 2013.

Enogex is constructing a cryogenic processing plant in Custer County, Oklahoma, which is expected add 200 MMcf/d of natural gas processing capacity to Enogex's system, and is expected to be supported by the installation of 6,000 horsepower of inlet compression and four miles of transmission pipeline. This plant will be connected to the Enogex "super-header" gathering system and is expected to be in service by the end of 2013.

The capital expenditures related to the above projects are presented in the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Future Capital Requirements and Financing Activities."

*Gas Gathering Acquisitions*

On August 1, 2012, Enogex entered into agreements with Chesapeake Midstream Gas Services, L.L.C. and Mid-America Midstream Gas Services, L.L.C., wholly-owned subsidiaries of Access Midstream Partners, L.P. and Chesapeake Midstream Development, L.P., respectively, pursuant to which Enogex agreed to acquire approximately 235 miles of natural gas gathering pipelines, right-of-ways and certain other midstream assets that provide natural gas gathering services in the greater Granite Wash area. The transactions closed on August 31, 2012. The aggregate purchase price for these transactions was approximately $78.6 million including reimbursement for certain permitted capital expenditures incurred during the period beginning June 1, 2012 and ending August 31, 2012. Enogex utilized cash generated from operations and bank borrowings to fund the purchase. In addition, Enogex also incurred acquisition-related costs of $3.5 million for sales taxes on acquired assets, which are included in taxes other than income. Enogex expects the purchase price allocations to be completed by the end of the first quarter of 2013. The Company believes that the acquisition transactions will provide Enogex with key new opportunities in the greater Granite Wash area.

In connection with these agreements, Enogex entered into a gas gathering and processing agreement with Chesapeake effective September 1, 2012 pursuant to which Enogex began providing fee-based natural gas gathering, compression, processing and transportation services to Chesapeake with respect to certain acreage dedicated by Chesapeake.

The capital expenditures related to the above agreements are presented in the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Future Capital Requirements and Financing Activities."

**2013 Outlook**

The Company's 2013 earnings guidance is between approximately $335 million and $360 million of net income, or $3.35 to $3.60 per average diluted share.

**Key assumptions for 2013 include:**

***Consolidated OGE***

- Approximately 100 million average diluted shares outstanding;
- An effective tax rate of approximately 30 percent; and
- A projected loss at the holding company between approximately $2 million and $4 million, or $0.02 to $0.04 per diluted share, primarily due to interest expense relating to long and short-term debt borrowings partially offset by tax deductions.

***OG&E***

The Company projects OG&E to earn approximately $280 million to $290 million or $2.80 to $2.90 per average diluted share in 2013 and is based on the following assumptions:

- Normal weather patterns are experienced for the remainder of the year;
- Gross margin on revenues of approximately $1.290 billion to $1.295 billion based on sales growth of approximately 1.5 percent on a weather-adjusted basis;
    - Approximately $75 million of gross margin is primarily attributed to regionally allocated transmission projects;
- Operating expenses of approximately $770 million to $780 million, with operation and maintenance expenses comprising 57 percent of the total;
- Interest expense of approximately $130 million to $135 million which assumes a $3 million allowance for borrowed funds used during construction reduction to interest expense and $250 million of long-term debt issued in the first half of 2013;
- Allowance for equity funds used during construction of approximately $10 million; and
- An effective tax rate of approximately 28 percent.

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

***Enogex***

The Company projects Enogex to earn approximately $55 million to $75 million, or $0.55 to $0.75 per average diluted share and EBITDA between $213 million and $241 million, in 2013 net of noncontrolling interest, and is based on the following assumptions:

- Total Enogex anticipated gross margin of between approximately $470 million and $500 million. The gross margin assumption includes:
  - Natural gas transportation and storage gross margin contribution of between approximately $130 million and $140 million, of which 83 percent is attributable to the transportation business;
  - Natural gas gathering and processing gross margin contribution of between approximately $340 million and $360 million, of which 51 percent is attributable to the processing business;
  - Key factors affecting the natural gas gathering and processing gross margin forecast are:
    - Assumed increase of approximately 10 to 15 percent in gathered volumes over 2012;
    - Assumed increase of approximately 10 to 15 percent in processable* volumes over 2012;
    - At the midpoint of Enogex's natural gas gathering and processing assumption Enogex has assumed:
      - An average processing contract mix of 48 percent fixed-fee, 23 percent percent-of-liquids, 19 percent percent-of-proceeds and 10 percent keep-whole;
      - Average natural gas price of $3.38 per MMBtu in 2013;
      - Average NGLs price of $0.82 per gallon in 2013;
      - Average price per gallon of condensate of $2.13 in 2013;
      - Ethane is projected to be in rejection for 2013;
      - Approximately 50 percent of NGLs volumes are expected to flow to Mt. Belvieu; and
      - A 10 percent change in the average NGLs price for the entire year impacts net income approximately $5 million;
- Enogex has assumed operating expenses of approximately $325 million to $335 million, with operation and maintenance expenses comprising 54 percent of the total;
- A pre-tax gain of approximately $10 million associated with asset sales in the first quarter of 2013;
- Interest expense of approximately $30 million to $35 million;
- An effective tax rate of approximately 38 percent; and
- ArcLight group will own approximately 22 percent of Enogex Holdings by the end of 2013.

**2014 Volume projections for Enogex:**

- Assumed increase of approximately five to 10 percent in gathered volumes over 2013; and
- Assumed increase of approximately 10 to 20 percent in processable* volumes over 2013.

***** Processable volumes are the natural gas production that are on Enogex's gathering systems that are available to be processed, some of which is moved off of the system and is not processed under one of Enogex's processing agreements. Processable volumes include condensate volumes which are captured in the gathering pipeline and therefore not included in plant inlet volumes.

EBITDA is a supplemental non-GAAP financial measure used by external users of the Company's financial statements such as investors, commercial banks and others; therefore, the Company has included the table below which provides a reconciliation of projected EBITDA to projected net income attributable to Enogex Holdings at the midpoint of Enogex Holdings' earnings assumptions for 2013, which does not include the effect of income taxes whereas OGE Energy's portion of Enogex Holdings' net income included in OGE Energy's earnings guidance does reflect the effect of income taxes. Enogex Holding's net income shown in the EBITDA table does not include the effect of income taxes because Enogex Holdings is a partnership and is not subject to income taxes. Each partner is responsible for paying their own income taxes. For a discussion of the reasons for the use of EBITDA, as well as its limitations as an analytical tool, see "Non-GAAP Financial Measure" below.

**Reconciliation of projected EBITDA to projected net income attributable to Enogex Holdings**

| *(In millions)* | | Twelve Months Ended December 31, 2013 (A)(B) |
|---|---|---|
| Net income attributable to Enogex Holdings | $ | 132 |
| Add: | | |
| Interest expense, net | | 33 |
| Depreciation and amortization expense (C) | | 123 |
| EBITDA | $ | 288 |
| OGE Energy's portion | $ | 228 |

(A) Based on the midpoint of Enogex Holdings' earnings guidance for 2013.
(B) As of November 1, 2010, Enogex Holdings' earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level.
(C) Includes amortization of certain customer-based intangible assets associated with the acquisition from Cordillera in November 2011, which is included in gross margin for financial reporting purposes.

**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, 2012, 2011 and 2010 and the Company's consolidated financial position at December 31, 2012 and 2011. The following information should be read in conjunction with the Consolidated Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

| Year ended December 31 *(In millions except per share data)* | | **2012** | | 2011 | | 2010 |
|---|---|---|---|---|---|---|
| Operating income | **$** | **676.9** | $ | 646.7 | $ | 593.9 |
| Net income attributable to OGE Energy | **$** | **355.0** | $ | 342.9 | $ | 295.3 |
| Basic average common shares outstanding | | **98.6** | | 97.9 | | 97.3 |
| Diluted average common shares outstanding | | **99.1** | | 99.2 | | 98.9 |
| Basic earnings per average common share attributable to OGE Energy common shareholders | **$** | **3.60** | $ | 3.50 | $ | 3.03 |
| Diluted earnings per average common share attributable to OGE Energy common shareholders | **$** | **3.58** | $ | 3.45 | $ | 2.99 |
| Dividends declared per common share | **$** | **1.5950** | $ | 1.5175 | $ | 1.4625 |

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

***Operating Income (Loss) by Business Segment***

| Year ended December 31 *(In millions)* | | **2012** | | 2011 | | 2010 |
|---|---|---|---|---|---|---|
| OG&E (Electric Utility) | **$** | **489.4** | $ | 472.3 | $ | 413.7 |
| Enogex (Natural Gas Midstream Operations) | | | | | | |
| Natural gas transportation and storage (A) | | **45.1** | | 56.4 | | 60.4 |
| Natural gas gathering and processing | | **140.5** | | 118.7 | | 123.9 |
| Other Operations (B) | | **1.9** | | (0.7) | | (4.1) |
| Consolidated operating income | **$** | **676.9** | $ | 646.7 | $ | 593.9 |

(A) During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented.
(B) Other Operations primarily includes the operations of the holding company and consolidating eliminations.

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

***OG&E (Electric Utility)***

| Year ended December 31 *(Dollars in millions)* | **2012** | 2011 | 2010 |
|---|---|---|---|
| Operating revenues | **$ 2,141.2** | $ 2,211.5 | $ 2,109.9 |
| Cost of goods sold | **879.1** | 1,013.5 | 1,000.2 |
| Gross margin on revenues | **1,262.1** | 1,198.0 | 1,109.7 |
| Other operation and maintenance | **446.3** | 436.0 | 418.1 |
| Depreciation and amortization | **248.7** | 216.1 | 208.7 |
| Taxes other than income | **77.7** | 73.6 | 69.2 |
| Operating income | **489.4** | 472.3 | 413.7 |
| Interest income | **0.2** | 0.5 | 0.1 |
| Allowance for equity funds used during construction | **6.2** | 20.4 | 11.4 |
| Other income | **8.0** | 8.0 | 6.5 |
| Other expense | **4.3** | 8.4 | 1.6 |
| Interest expense | **124.6** | 111.6 | 103.4 |
| Income tax expense | **94.6** | 117.9 | 111.0 |
| Net income | **$ 280.3** | $ 263.3 | $ 215.7 |
| Operating revenues by classification | | | |
| Residential | **$ 878.0** | $ 943.5 | $ 894.8 |
| Commercial | **523.5** | 531.3 | 521.0 |
| Industrial | **206.8** | 216.0 | 212.5 |
| Oilfield | **163.4** | 165.1 | 162.8 |
| Public authorities and street light | **202.4** | 207.4 | 200.8 |
| Sales for resale | **54.9** | 65.3 | 65.8 |
| System sales revenues | **2,029.0** | 2,128.6 | 2,057.7 |
| Off-system sales revenues | **36.5** | 36.2 | 21.7 |
| Other | **75.7** | 46.7 | 30.5 |
| Total operating revenues | **$ 2,141.2** | $ 2,211.5 | $ 2,109.9 |
| MWH sales by classification *(In millions)* | | | |
| Residential | **9.1** | 9.9 | 9.6 |
| Commercial | **7.0** | 6.9 | 6.7 |
| Industrial | **4.0** | 3.9 | 3.8 |
| Oilfield | **3.3** | 3.2 | 3.1 |
| Public authorities and street light | **3.3** | 3.2 | 3.0 |
| Sales for resale | **1.3** | 1.4 | 1.4 |
| System sales | **28.0** | 28.5 | 27.6 |
| Off-system sales | **1.4** | 1.0 | 0.5 |
| Total sales | **29.4** | 29.5 | 28.1 |
| Number of customers | **798,110** | 789,146 | 782,558 |
| Weighted-average cost of energy per kilowatt-hour - cents | | | |
| Natural gas | **2.930** | 4.328 | 4.638 |
| Coal | **2.310** | 2.064 | 1.911 |
| Total fuel | **2.437** | 2.897 | 3.012 |
| Total fuel and purchased power | **2.806** | 3.215 | 3.309 |
| Degree days (A) | | | |
| Heating - Actual | **2,667** | 3,359 | 3,528 |
| Heating - Normal | **3,349** | 3,631 | 3,631 |
| Cooling - Actual | **2,561** | 2,776 | 2,328 |
| Cooling - Normal | **2,092** | 1,911 | 1,911 |

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

***2012 compared to 2011.*** OG&E's operating income increased $17.1 million, or 3.6 percent, in 2012 as compared to 2011 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense and higher depreciation and amortization expense.

***Gross Margin***

Operating revenues were $2,141.2 million in 2012 as compared to $2,211.5 million in 2011, a decrease of $70.3 million, or 3.2 percent. Cost of goods sold was $879.1 million in 2012 as compared to $1,013.5 million in 2011, a decrease of $134.4 million, or 13.3 percent. Gross margin was $1,262.1 million in 2012 as compared to $1,198.0 million in 2011, an increase of $64.1 million, or 5.4 percent. The below factors contributed to the change in gross margin:

| | $ Change |
|---|---|
| | *(In millions)* |
| Price variance (A) | $ 54.1 |
| Wholesale transmission revenue (B) | 28.5 |
| New customer growth | 11.5 |
| Non-residential demand and related revenues | 4.9 |
| Enogex transportation credit (C) | 3.3 |
| Arkansas rate increase | 2.8 |
| Oklahoma rate increase | 2.7 |
| Renewal of wholesale contract with customer | 1.3 |
| Other | 0.3 |
| Quantity variance (primarily weather) | (45.3) |
| Change in gross margin | $ 64.1 |

(A) Increased due to revenues from the recovery of investments, including the Crossroads wind farm and smart grid.
(B) Increased primarily due to the inclusion of construction work in progress in transmission rates for specific FERC approved projects that previously accrued allowance for funds used during construction.
(C) Increased due to a credit to OG&E's customers in 2011 related to the settlement of OG&E's 2009 fuel adjustment clause review.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $642.4 million in 2012 as compared to $775.0 million in 2011, a decrease of $132.6 million, or 17.1 percent, primarily due to lower natural gas prices. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. In 2012, OG&E's fuel mix was 52 percent coal, 42 percent natural gas and six percent wind. In 2011, OG&E's fuel mix was 58 percent coal, 39 percent natural gas and three percent wind. Purchased power costs were $223.0 million in 2012 as compared to $230.7 million in 2011, a decrease of $7.7 million, or 3.3 percent, primarily due to a decrease in cogeneration purchases and purchases in the energy imbalance service market due to milder weather partially offset by an increase in short-term power purchases. Transmission related charges were $13.7 million in 2012 as compared to $7.8 million in 2011, an increase of $5.9 million, or 75.6 percent, primarily due to higher SPP charges for the base plan projects of other utilities.

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 $446.3 million in 2012 as compared to $436.0 million in 2011, an increase of $10.3 million, or 2.4 percent. The below factors contributed to the change in other operations and maintenance expense:

| | $ Change |
|---|---|
| | *(In millions)* |
| Salaries and wages (A) | $ 6.4 |
| Contract professional and technical services (related to smart grid) (B) | 4.2 |
| Employee benefits (C) | 3.4 |
| Administration and assessment fees (primarily SPP and North American Electric Reliability Corporation) | 3.4 |
| Wind farm lease expense (primarily Crossroads) (B) | 3.0 |
| Injuries and damages | 1.9 |
| Ongoing maintenance at power plants (B) | 1.9 |
| Software (primarily smart grid) (B) | 1.8 |
| Other | 0.2 |
| Temporary labor | (1.7) |
| Uncollectibles | (2.4) |
| Vegetation management (primarily system hardening) (B) | (3.0) |
| Allocations from holding company (primarily lower contract professional services and lower payroll and benefits) | (3.1) |
| Capitalized labor | (5.7) |
| Change in other operation and maintenance expense | $ 10.3 |

(A) Increased primarily due to salary increases and an increase in incentive compensation expense partially offset by lower headcount in 2012 and a decrease in overtime expense.
(B) Includes costs that are being recovered through a rider.
(C) Increased primarily due to an increase in worker's compensation accruals, an increase in medical expense and an increase in postretirement medical expense partially offset by a decrease in pension expense.

Depreciation and amortization expense was $248.7 million in 2012 as compared to $216.1 million in 2011, an increase of $32.6 million, or 15.1 percent, primarily due to additional assets being placed in service throughout 2011 and 2012, including the Crossroads wind farm, which was fully in service in January 2012, the Sooner-Rose Hill and Sunnyside-Hugo transmission projects, which were fully in service in April 2012, and the smart grid project which was completed in late 2012.

***Additional Information***

*Allowance for Equity Funds Used During Construction.* Allowance for equity funds used during construction was $6.2 million in 2012 as compared to $20.4 million in 2011, a decrease of $14.2 million, or 69.6 percent, primarily due to higher levels of construction costs for the Crossroads wind farm in 2011.

*Other Income.* Other income was $8.0 million in both 2012 and 2011. Factors affecting other income included an increased margin of $8.8 million recognized in the guaranteed flat bill program in 2012 as a result of milder weather offset by a decrease of $8.9 million related to the benefit associated with the tax gross-up of allowance for equity funds used during construction.

*Other Expense.* Other expense was $4.3 million in 2012 as compared to $8.4 million in 2011, a decrease of $4.1 million, or 48.8 percent primarily due to a decrease in charitable contributions.

*Interest Expense.* Interest expense was $124.6 million in 2012 as compared to $111.6 million in 2011, an increase of $13.0 million, or 11.6 percent, primarily due to a $6.9 million increase in interest expense related to lower allowance for borrowed funds used during construction costs for the Crossroads wind farm in 2011 and a $5.5 million increase in interest expense related to the issuance of long-term debt in May 2011.

*Income Tax Expense.* Income tax expense was $94.6 million in 2012 as compared to $117.9 million in 2011, a decrease of $23.3 million, or 19.8 percent. The decrease in income tax expense was primarily due to an increase in the amount of Federal renewable energy tax credits recognized associated with the Crossroads wind farm and lower pre-tax income in 2012 as compared to 2011.

***2011 compared to 2010.*** OG&E's operating income increased $58.6 million, or 14.2 percent, in 2011 as compared to 2010 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense.

***Gross Margin***

Operating revenues were $2,211.5 million in 2011 as compared to $2,109.9 million in 2010, an increase of $101.6 million, or 4.8 percent. Cost of goods sold was $1,013.5 million in 2011 as compared to $1,000.2 million in 2010, an increase of $13.3 million, or 1.3 percent. Gross margin was $1,198.0 million in 2011 as compared to $1,109.7 million in 2010, an increase of $88.3 million, or 8.0 percent. The below factors contributed to the change in gross margin:

| | $ Change |
|---|---|
| | *(In millions)* |
| Quantity variance (primarily weather) | $ 27.4 |
| Price variance (A) | 23.9 |
| Transmission revenue (B) | 15.3 |
| New customer growth | 13.1 |
| Arkansas rate increase | 6.0 |
| Non-residential demand and related revenues | 5.0 |
| Renewal of wholesale contract with customer | 3.1 |
| Other | 0.2 |
| Enogex transportation credit (C) | (5.7) |
| Change in gross margin | $ 88.3 |

(A) Increased due to revenues from the recovery of investments, including the Windspeed transmission line, Oklahoma demand program, smart grid, system hardening, storm recovery, the Crossroads wind farm and the OU Spirit wind farm, and higher revenues from industrial and oilfield customers.

(B) Increased primarily due to the inclusion of construction work in progress in transmission rates for specific FERC approved projects that previously accrued allowance for funds used during construction.

(C) Decreased due to a credit to OG&E's customers in 2011 related to the settlement of OG&E's 2009 fuel adjustment clause review.

Fuel expense was $775.0 million in 2011 as compared to $771.0 million in 2010, an increase of $4.0 million, or 0.5 percent, primarily due to higher generation primarily due to warmer weather in OG&E's service territory. 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 2011, OG&E's fuel mix was 58 percent coal, 39 percent natural gas and three percent wind. In 2010, OG&E's fuel mix was 55 percent coal, 42 percent natural gas and three percent wind. Purchased power costs were $230.7 million in 2011 as compared to $226.5 million in 2010, an increase of $4.2 million, or 1.9 percent, primarily due to an increase in short-term power purchases partially offset by a decrease in purchases in the energy imbalance service market and a decrease in cogeneration cost.

***Operating Expenses***

Other operation and maintenance expenses were $436.0 million in 2011 as compared to $418.1 million in 2010, an increase of $17.9 million, or 4.3 percent. The below factors contributed to the change in other operations and maintenance expense:

| | $ Change |
|---|---|
| | *(In millions)* |
| Allocations from holding company (A) | $ 15.5 |
| Salaries and wages (B) | 12.1 |
| Other marketing and sales expense (primarily demand-side management initiatives) (C) | 4.6 |
| Uncollectible expense | 3.1 |
| Fleet transportation expense (primarily higher fuel costs in 2011) | 1.6 |
| Temporary labor expense | 1.3 |
| Administration and assessment fees (primarily SPP) | 1.2 |
| Vegetation management (primarily system hardening) (C) | (2.9) |
| Other | (3.8) |
| Injuries and damages (primarily higher reserves on claims in 2010) | (5.0) |
| Employee benefits (D) | (9.8) |
| Change in other operation and maintenance expense | $ 17.9 |

(A) Increased primarily related to payroll and benefits expense, contract technical and construction services and contract professional services.
(B) Increased primarily due to salary increases in 2011, increased incentive compensation expense and increased overtime expense primarily due to storms in April and August 2011.
(C) Includes costs that are being recovered through a rider.
(D) Decreased primarily due to a decrease in postretirement benefits expense related to amendments to the Company's retiree medical plan adopted in January 2011 (see Note 14 of Notes to Consolidated Financial Statements) partially offset by a modification to OG&E's pension tracker and a decrease in worker's compensation accruals in 2011.

***Additional Information***

*Allowance for Equity Funds Used During Construction.* Allowance for equity funds used during construction was $20.4 million in 2011 as compared to $11.4 million in 2010, an increase of $9.0 million, or 78.9 percent, primarily due to higher levels of construction costs for the Crossroads wind farm in 2011.

*Other Income.* Other income was $8.0 million in 2011 as compared to $6.5 million in 2010, an increase of $1.5 million, or 23.1 percent. The increase in other income was primarily due to a benefit of $5.6 million associated with the tax gross-up of allowance for equity funds used during construction partially offset by increased losses of $4.2 million recognized in the guaranteed flat bill program in 2011 from higher than expected usage resulting from warmer weather.

*Other Expense.* Other expense was $8.4 million in 2011 as compared to $1.6 million in 2010, an increase of $6.8 million, primarily due to an increase in charitable contributions of $6.4 million as the holding company made the charitable contributions in 2010.

*Interest Expense.* Interest expense was $111.6 million in 2011 as compared to $103.4 million in 2010, an increase of $8.2 million, or 7.9 percent, primarily due to a $14.0 million increase related to the issuance of long-term debt in June 2010 and May 2011. This increase in interest expense was partially offset by:

- a $4.9 million decrease in interest expense due to a higher allowance for borrowed funds used during construction primarily due to construction costs for the Crossroads wind farm; and
- a $1.4 million decrease in interest expense in 2011 due to interest to customers related to the fuel over recovery balance in 2010.

*Income Tax Expense.* Income tax expense was $117.9 million in 2011 as compared to $111.0 million in 2010, an increase of $6.9 million, or 6.2 percent. The increase in income tax expense was primarily due to higher pre-tax income in 2011 as compared to 2010. This increase in income tax expense was partially offset by:

- the one-time, non-cash charge in 2010 for the elimination of the tax deduction for the Medicare Part D subsidy;
- the write-off of previously recognized Oklahoma investment tax credits in 2010 primarily due to expenditures no longer eligible for the Oklahoma investment tax credit related to the change in the tax method of accounting for capitalization of repair expenditures; and
- higher Oklahoma investment tax credits in 2011 as compared to 2010.

***Enogex (Natural Gas Midstream Operations)***

| **2012** | Natural Gas Transportation and Storage | Natural Gas Gathering and Processing | Eliminations | Total |
|---|---|---|---|---|
| *(In millions)* | | | | |
| Operating revenues | **$ 639.5** | **$ 1,222.6** | **$ (253.5)** | **$ 1,608.6** |
| Cost of goods sold | **504.9** | **868.7** | **(253.5)** | **1,120.1** |
| Gross margin on revenues | **134.6** | **353.9** | **—** | **488.5** |
| Other operation and maintenance | **49.8** | **123.1** | **—** | **172.9** |
| Depreciation and amortization | **24.0** | **84.8** | **—** | **108.8** |
| Impairment of assets | **—** | **0.4** | **—** | **0.4** |
| Gain on insurance proceeds | **—** | **(7.5)** | **—** | **(7.5)** |
| Taxes other than income | **15.7** | **12.6** | **—** | **28.3** |
| Operating income | **$ 45.1** | **$ 140.5** | **$ —** | **$ 185.6** |

| 2011 | Natural Gas Transportation and Storage | Natural Gas Gathering and Processing | Eliminations | Total |
|---|---|---|---|---|
| *(In millions)* | | | | |
| Operating revenues | $ 880.1 | $ 1,167.1 | $ (260.1) | $ 1,787.1 |
| Cost of goods sold | 736.0 | 870.7 | (260.1) | 1,346.6 |
| Gross margin on revenues | 144.1 | 296.4 | — | 440.5 |
| Other operation and maintenance | 50.7 | 111.8 | — | 162.5 |
| Depreciation and amortization | 22.0 | 55.6 | — | 77.6 |
| Impairment of assets | — | 6.3 | — | 6.3 |
| Gain on insurance proceeds | — | (3.0) | — | (3.0) |
| Taxes other than income | 15.0 | 7.0 | 0.1 | 22.1 |
| Operating income | $ 56.4 | $ 118.7 | $ (0.1) | $ 175.0 |

| 2010 | Natural Gas Transportation and Storage | Natural Gas Gathering and Processing | Eliminations | Total |
|---|---|---|---|---|
| *(In millions)* | | | | |
| Operating revenues | $ 984.8 | $ 1,005.6 | $ (282.7) | $ 1,707.7 |
| Cost of goods sold | 834.5 | 733.3 | (282.7) | 1,285.1 |
| Gross margin on revenues | 150.3 | 272.3 | — | 422.6 |
| Other operation and maintenance | 53.8 | 91.5 | — | 145.3 |
| Depreciation and amortization | 21.2 | 50.1 | — | 71.3 |
| Impairment of assets | 0.7 | 0.4 | — | 1.1 |
| Taxes other than income | 14.2 | 6.4 | — | 20.6 |
| Operating income | $ 60.4 | $ 123.9 | $ — | $ 184.3 |

***Operating Data***

| Year ended December 31 | | **2012** | | 2011 | | 2010 |
|---|---|---|---|---|---|---|
| Gathered volumes – TBtu/d | | **1.41** | | 1.36 | | 1.32 |
| Incremental transportation volumes – TBtu/d (A) | | **0.67** | | 0.58 | | 0.40 |
| Total throughput volumes – TBtu/d | | **2.08** | | 1.94 | | 1.72 |
| Natural gas processed – TBtu/d | | **0.98** | | 0.79 | | 0.82 |
| Condensate sold – million gallons | | **35** | | 27 | | 24 |
| Average condensate sales price per gallon | **$** | **1.95** | $ | 2.09 | $ | 1.81 |
| NGLs sold (keep-whole) – million gallons | | **162** | | 167 | | 187 |
| NGLs sold (purchased for resale) – million gallons | | **667** | | 487 | | 470 |
| NGLs sold (percent-of-liquids) – million gallons | | **24** | | 25 | | 26 |
| NGLs sold (percent-of-proceeds) – million gallons | | **14** | | 6 | | 5 |
| Total NGLs sold – million gallons | | **867** | | 685 | | 688 |
| Average NGLs sales price per gallon | **$** | **0.89** | $ | 1.16 | $ | 0.96 |
| Average natural gas sales price per MMBtu | **$** | **2.79** | $ | 4.08 | $ | 4.24 |

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

***2012 compared to 2011.*** Enogex's operating income increased $10.6 million, or 6.1 percent, in 2012 as compared to 2011. This increase was primarily due to a higher gross margin, a higher gain on insurance proceeds related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant discussed below and lower impairment of assets partially offset by higher other operation and maintenance expense, higher depreciation and amortization expense and higher taxes other than income. The higher gross margin related to (i) increased gathering rates and volumes associated with ongoing expansion projects and increased volumes from gas gathering assets acquired in November 2011 and August 2012 and (ii) increased inlet volumes resulting from the return to full service of the Cox City natural gas processing plant in September 2011, the South Canadian natural gas processing plant, which was placed in service in December 2011, and the Wheeler natural gas processing plant, which was placed in service in August 2012. These increases in gross margin were partially offset by lower average natural gas and NGLs prices. In 2012, imbalance volume changes and realized margin on physical gas long/short positions decreased the gross margin by $7.5 million, net of corresponding imbalance and fuel tracker balances and the impact of the recovery of prior years' under-recovered fuel positions during 2012.

Other operation and maintenance expense increased $10.4 million, or 6.4 percent, primarily due to:

- increased payroll and benefits costs due to increased headcount to support business growth; and
- increased rental expense on compression due to leases acquired in the August 2012 gas gathering acquisition partially offset by the reduction of rental payments on the Atoka plant, which was taken out of service in August 2011.

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

- decreased costs for soil remediation projects; and
- lower contract technical and professional services expense and materials and supplies expense due to a decrease in non-capital projects during 2012.

Depreciation and amortization expense increased $31.2 million, or 40.2 percent, primarily due to additional assets placed in service throughout 2011 and 2012, including the gas gathering assets acquired in November 2011 and August 2012.

Impairment of assets decreased $5.9 million, or 93.7 percent, primarily due to an impairment of $5.0 million related to a management decision in August 2011 to use third-party processing exclusively for gathered volumes dedicated to the Atoka processing plant and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. The noncontrolling interest portion of the impairment was $2.5 million which was included in Net Income Attributable to Noncontrolling Interests in the Company's Consolidated Statement of Income.

Gain on insurance proceeds increased $4.5 million related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant.

Taxes other than income increased $6.2 million, or 28.1 percent, primarily due to:

- sales tax of $3.5 million related to the acquisition of certain gas gathering assets in September 2012 as discussed in Note 3 of Notes to Consolidated Financial Statements; and
- increased ad valorem taxes resulting from additional assets placed in service throughout 2011 and 2012.

***Natural Gas Transportation and Storage***

The natural gas transportation and storage business contributed $134.6 million of Enogex's consolidated gross margin during 2012 as compared to $144.1 million during 2011, a decrease of $9.5 million or 6.6 percent. The transportation operations contributed $110.1 million of Enogex's consolidated gross margin during 2012 as compared to $118.8 million during 2011. The storage operations contributed $24.5 million of Enogex's consolidated gross margin during 2012 as compared to $25.3 million during 2011. Gross margin decreased primarily due to:

- lower volumes and realized margin on sales of physical natural gas long positions associated with transportation operations, which decreased the gross margin by $6.4 million, net of imbalances and fuel tracker balances;
- lower storage fees due to terminated contracts and renegotiated contracts with less favorable terms, which decreased the gross margin by $2.5 million;
- lower gains on storage sales during 2012, which decreased the gross margin by $1.9 million;
- lower crosshaul revenues in 2012 resulting from the reversal of a previously recognized reserve of $3.0 million associated with the settlement of Enogex's 2009 FERC Section 311 rate case during 2011 partially offset by increased utilization of $1.3 million during 2012, which decreased the gross margin by $1.7 million; and
- lower transportation fees due to unbundling of transportation and gathering fees as contracts are renegotiated, which decreased the gross margin by $1.4 million.

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

- higher realized margin on hedging activity associated with natural gas storage inventory from storage, which increased the gross margin by $4.4 million; and
- higher transportation demand fees as a result of new contracts, which increased the gross margin by $2.3 million.

Other operation and maintenance expense for the natural gas transportation and storage business was $0.9 million, or 1.8 percent, lower during 2012 as compared to 2011 primarily due to lower contract technical and professional services expense and materials and supplies expense due to a decrease in non-capital projects during 2012 partially offset by increased payroll and benefits costs due to increased headcount to support business growth.

***Natural Gas Gathering and Processing***

The natural gas gathering and processing business contributed $353.9 million of Enogex's consolidated gross margin during 2012 as compared to $296.4 million during 2011, an increase of $57.5 million, or 19.4 percent. The gathering operations contributed $145.9 million of Enogex's consolidated gross margin during 2012 as compared to $125.2 million during 2011. The processing operations contributed $208.0 million of Enogex's consolidated gross margin during 2012 as compared to $171.2 million during 2011.

During 2012, Enogex realized a higher gross margin in its natural gas gathering and processing operations related to (i) increased gathering rates and volumes associated with ongoing expansion projects, primarily in the Granite Wash play, which has added richer natural gas to Enogex's system, and increased volumes from gas gathering assets acquired in November 2011 and August 2012, (ii) increased inlet volumes resulting from the return to full service of the Cox City natural gas processing plant in September 2011, the South Canadian natural gas processing plant, which was placed in service in December 2011, and the Wheeler natural gas processing plant, which was placed in service in August 2012, and (iii) contract conversion of one of Enogex's five largest customer's Oklahoma production volumes to fixed fee effective July 1, 2011. These increases in the gathering and processing gross margin were partially offset by lower average natural gas and NGLs prices.

The above factors contributed to the increase in the natural gas gathering and processing gross margin as follows:

- an increased gross margin on keep-whole processing of $28.4 million;
- an increase in gathering fees associated with ongoing expansion projects and increased volumes from gas gathering assets, which increased the gross margin by $16.8 million;

- an increase in condensate revenues associated with higher condensate margins and volumes, which increased the gross margin by $14.2 million; and
- an increased gross margin on fixed-fee contracts of $8.4 million.

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

- an increase in the utilization of third-party processing as a result of (i) the Atoka processing plant being taken out of service in August 2011 and (ii) increased activity from western Oklahoma and Texas Panhandle expansion projects currently processed by third parties, which together decreased the gross margin by $6.2 million;
- a decrease in percent-of-liquids and percent-of-proceeds margins of $4.4 million; and
- lower volumes and realized margin on sales of physical natural gas long positions associated with gathering operations, which decreased the gross margin by $1.1 million, net of imbalances and fuel tracker obligations.

Other operation and maintenance expense for the natural gas gathering and processing business was $11.3 million, or 10.1 percent, higher during 2012 as compared to 2011 primarily due to:

- increased payroll and benefits costs due to increased headcount to support business growth; and
- increased rental expense on compression due to leases acquired in the August 2012 gas gathering acquisition partially offset by the reduction of rental payments on the Atoka plant, which was taken out of service in August 2011.

These increases in other operation and maintenance expense were partially offset by decreased costs for soil remediation projects.

***Enogex Consolidated Information***

*Other Income.* Enogex's consolidated other income was $1.0 million during 2012 as compared to $3.9 million during 2011, a decrease of $2.9 million, or 74.4 percent, due to the recognition in April 2011 of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets.

*Other Expense.* Enogex's consolidated other expense was $4.5 million during 2012 as compared to $1.3 million during 2011, an increase of $3.2 million due to higher non-cash losses on retirements of equipment during 2012.

*Interest Expense.* Enogex's consolidated interest expense was $32.6 million during 2012 as compared to $22.9 million during 2011, an increase of $9.7 million, or 42.4 percent, primarily due to:

- a decrease in capitalized interest during 2012 due to the completion of several large capital projects as compared to 2011;
- higher borrowings partially offset by repayments under Enogex's revolving credit agreement during 2012 as compared to 2011; and
- borrowings under Enogex's term loan during 2012 with no comparable item during 2011.

*Income Tax Expense.* Enogex's consolidated income tax expense was $45.7 million during 2012 as compared to $51.7 million during 2011, a decrease of $6.0 million, or 11.6 percent, primarily due to lower pre-tax income (net of noncontrolling interest) during 2012 as compared to 2011.

*Noncontrolling Interest.* Enogex's net income attributable to noncontrolling interest was $29.7 million during 2012 as compared to $20.8 million during 2011, an increase of $8.9 million or 42.8 percent, due to higher net income, the ArcLight group's increased ownership in Enogex Holdings as a result of the ArcLight group funding capital contributions at a disproportionate percentage to OGE Holdings throughout 2011 and an impairment recorded in August 2011 related to the Atoka processing plant.

*Non-Recurring Items.* During 2012, Enogex had an increase in net income of $4.6 million due to a gain on insurance proceeds related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant partially offset by a decrease in net income of $2.1 million related to sales taxes on the assets acquired in the gas gathering acquisitions in August 2012, as discussed in Note 3 of Notes to Consolidated Financial Statements, which Enogex does not consider to be reflective of its ongoing performance. During 2011, Enogex had an increase in net income of $2.3 million relating to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011, which Enogex does not consider to be reflective of its ongoing performance.

***2011 compared to 2010.*** Enogex's operating income decreased $9.3 million, or 5.0 percent, in 2011 as compared to 2010. This decrease was primarily due to higher other operation and maintenance expense, higher depreciation and amortization expense, lower average natural gas prices and a slight decrease in inlet processing volumes related to the 120 MMcf/d Cox City natural gas processing plant being out of service due to the fire from December 2010 until September 2011 and the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011. These decreases were partially offset by higher NGLs prices and increased gathered volumes associated with ongoing expansion projects. In 2011, imbalance volume changes and realized margin on physical gas long/short positions decreased the gross margin by $14.8 million, net of corresponding imbalance and fuel tracker balances and the impact of the recovery of prior years' under-recovered fuel positions during 2010.

Other operation and maintenance expense increased $17.2 million, or 11.8 percent, primarily due to:

- increased payroll and benefits costs due to increased headcount to support business growth;
- increased contract technical and professional services expense and materials and supplies expense due to an increase in non-capital projects in 2011;
- increased property insurance costs;
- increased rental expense due to growing demand for compression as Enogex's business expands; and
- increased costs due to soil remediation projects.

Depreciation and amortization expense increased $6.3 million, or 8.8 percent, primarily due to additional assets placed in service throughout 2010 and 2011.

Impairment of assets increased $5.2 million in 2011 primarily due to an impairment of $5.0 million related to a management decision in August 2011 to use third-party processing exclusively for gathered volumes dedicated to the Atoka processing plant and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. The noncontrolling interest portion of the impairment was $2.5 million which was included in Net Income Attributable to Noncontrolling Interests in the Company's Consolidated Statement of Income.

Gain on insurance proceeds was $3.0 million in 2011 with no comparable item in 2010. The gain on insurance proceeds was for reimbursement related to the damaged train at the Cox City natural gas processing plant being replaced and the facility being returned to full service in September 2011.

***Natural Gas Transportation and Storage***

The natural gas transportation and storage business contributed $144.1 million of Enogex's gross margin in 2011 as compared to $150.3 million in 2010, a decrease of $6.2 million, or 4.1 percent. The transportation operations contributed $118.8 million of Enogex's consolidated gross margin in 2011 as compared to $116.9 million in 2010. The storage operations contributed $25.3 million of Enogex's consolidated gross margin in 2011 as compared to $33.4 million in 2010. Gross margin decreased primarily due to:

- lower volumes and realized margin on sales of physical natural gas long positions associated with transportation operations in 2011. Gross margin in 2011 included the under recovery of fuel positions as compared to 2010 that included the recovery of prior year's under-recovered fuel positions, which reduced the gross margin in 2011 by $12.1 million, net of imbalance and fuel tracker obligations;
- lower of cost or market adjustments on the natural gas storage inventory reflective of higher inventory volumes in 2011, which decreased the gross margin by $4.4 million; and
- lower realized margin on sale of natural gas inventory from storage due to a reduction in the realized natural gas market spreads, which decreased the gross margin by $2.8 million.

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

- higher capacity lease services under the MEP and Gulf Crossing capacity leases in 2011 as a result of pipeline integrity work on an Enogex pipeline in 2010, which increased the gross margin by $7.1 million;
- higher firm 311 services due to new contracts with more favorable rates in 2011, which increased the gross margin by $5.4 million;
- more favorable results from Enogex's customer-focused risk management services, natural gas marketing activities and trading activities and the expiration of an unfavorable transportation contract, which increased the gross margin by $2.2 million;

- higher interruptible transportation fees due to new contracts with more favorable rates in 2011, which increased the gross margin by $1.6 million; and
- higher crosshaul revenues in 2011 resulting from the reversal of a previously recognized reserve of $3.0 million associated with the settlement of Enogex's 2009 FERC Section 311 rate case partially offset by decreased utilization of $2.5 million in 2011 due to shippers utilizing crosshaul service in 2010 as a result of pipeline integrity work, which increased the 2011 gross margin by $0.5 million.

Other operation and maintenance expense for the natural gas transportation and storage business was $3.1 million, or 5.8 percent, lower in 2011 as compared to 2010 primarily due to decreased contract technical and professional services expense and materials and supplies expense due to a decrease in non-capital projects in 2011 partially offset by an increase in payroll and benefits costs due to increased headcount to support business growth.

***Natural Gas Gathering and Processing***

The natural gas gathering and processing business contributed $296.4 million of Enogex's consolidated gross margin in 2011 as compared to $272.3 million in 2010, an increase of $24.1 million, or 8.9 percent. The gathering operations contributed $125.2 million of Enogex's consolidated gross margin in 2011 as compared to $117.6 million in 2010. The processing operations contributed $171.2 million of Enogex's consolidated gross margin in 2011 as compared to $154.7 million in 2010.

In 2011, Enogex realized a higher gross margin in its natural gas gathering and processing operations primarily as the result of continued growth in gathered volumes from ongoing expansion projects, primarily in the Granite Wash play and Cana/Woodford Shale play, which has added richer natural gas to Enogex's system and higher NGLs prices. Although gathered volumes increased over 2010, gathering and processing volumes grew at a slower pace during the fourth quarter of 2011 than Enogex had anticipated. The increased gathering volumes were partially offset by the contract conversion of one of Enogex's five largest customer's Oklahoma production volumes to fixed fee effective July 1, 2011, a slight decrease in inlet processing volumes related to the 120 MMcf/d Cox City natural gas processing plant being out of service due to the fire from December 2010 until September 2011, the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011 and lower average natural gas prices.

The above factors contributed to the increase in the natural gas gathering and processing gross margin as follows:

- an increase in condensate revenues associated with higher condensate prices and volumes, which increased the gross margin by $11.1 million;
- an increase in gathering fees associated with ongoing expansion projects, which increased the gross margin by $10.7 million;
- an increased gross margin on keep-whole processing of $4.8 million;
- an increased gross margin on percent-of-liquids and percent-of-proceeds contracts of $2.6 million; and
- an increased gross margin on fixed-fee contract of $1.3 million.

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

- an increase in the utilization of third-party processing as a result of the reduced capacity related to the Cox City processing plant being out of service until September 2011 and the Atoka processing plant being taken out of service in August 2011, which decreased the gross margin by $3.4 million; and
- lower volumes and realized margin on sales of physical natural gas long positions associated with gathering operations, which decreased the gross margin in 2011 by $2.7 million, net of imbalance and fuel tracker obligations.

Other operation and maintenance expense for the natural gas gathering and processing business was $20.3 million, or 22.2 percent, higher in 2011 as compared to 2010 primarily due to:

- increased payroll and benefits costs due to increased headcount to support business growth;
- increased contract technical and professional services expense and materials and supplies expense due to an increase in non-capital projects in 2011;
- increased rental expense due to growing demand for compression as Enogex's business expands; and
- increased costs due to soil remediation projects.

### *Enogex Consolidated Information*

*Other Income*. Enogex's consolidated other income was $3.9 million in 2011 as compared to $0.2 million in 2010, an increase of $3.7 million, primarily due to the recognition of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011.

*Interest Expense*. Enogex's consolidated interest expense was $22.9 million in 2011 as compared to $30.4 million in 2010, a decrease of $7.5 million, or 24.7 percent, primarily due to:

- an increase of $6.1 million in capitalized interest related to increased construction activity in 2011; and
- a decrease of $1.0 million in interest expense in 2011 due to the retirement of long-term debt in January 2010.

*Income Tax Expense*. Enogex's consolidated income tax expense was $51.7 million in 2011 as compared to $57.7 million in 2010, a decrease of $6.0 million, or 10.4 percent, primarily due to:

- lower pre-tax income in 2011 as compared to 2010; and
- the one-time, non-cash charge in 2010 for the elimination of the tax deduction for the Medicare Part D subsidy.

*Noncontrolling Interest*. Enogex's net income attributable to noncontrolling interest was $20.8 million in 2011 as compared to $5.1 million in 2010, an increase of $15.7 million, due to the equity sale of a membership interest in Enogex Holdings to the ArcLight group partially offset by an impairment recorded in August 2011 related to the Atoka processing plant.

*Non-Recurring Item*. During 2011, Enogex had an increase in net income of $2.3 million relating to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011, which Enogex does not consider to be reflective of its ongoing performance.

*Timing Item*. Enogex's net income in 2011 was $82.2 million, which included a loss of $2.6 million resulting from recording Enogex'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 quarter of 2012.

### *Non-GAAP Financial Measure*

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

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

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

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

**Reconciliation of EBITDA to net income attributable to Enogex Holdings**

| *(In millions)* | | **2012** | | 2011 | | 2010 |
|---|---|---|---|---|---|---|
| Net income attributable to Enogex Holdings | **$** | **147.8** | $ | 155.9 | $ | 476.1 |
| Add: | | | | | | |
| Interest expense, net | | **32.6** | | 22.9 | | 30.3 |
| Income tax expense (A) | | **0.2** | | 0.2 | | (325.0) |
| Depreciation and amortization expense (B) | | **111.6** | | 77.2 | | 70.2 |
| EBITDA | **$** | **292.2** | $ | 256.2 | $ | 251.6 |
| OGE Energy's portion | **$** | **236.6** | $ | 222.9 | $ | 248.8 |

(A) As of November 1, 2010, Enogex Holdings' earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level.

(B) Includes amortization of certain customer-based intangible assets associated with the acquisition from Cordillera in November 2011, which is included in gross margin for financial reporting purposes.

**Off-Balance Sheet Arrangement**

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

OG&E has a noncancellable operating lease with purchase options, covering 1,389 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. On December 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $22.8 million.

On January 11, 2012, OG&E executed a five-year lease agreement for 135 railcars to replace railcars that have been taken out of service or destroyed. OG&E is also required to maintain all of the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

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**Liquidity and Capital Resources**

***Working Capital***

Working capital is defined as the amount by which current assets exceed current liabilities. The Company's working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from, customers, the level and timing of spending for maintenance and expansion activity, inventory levels and fuel recoveries.

The balance of Accounts Receivable, Net and Accrued Unbilled Revenues was $352.7 million and $381.8 million at December 31, 2012 and 2011, respectively, a decrease of $29.1 million, or 7.6 percent, primarily due to a decrease in billings to OG&E's customers in 2012 due to milder weather in 2012, a decrease at Enogex due to lower natural gas sales volumes and prices and the timing of customer payments received partially offset by higher transmission revenue and increased rates at OG&E.

The balance of Accounts Payable was $396.7 million and $388.0 million at December 31, 2012 and 2011, respectively, an increase of $8.7 million, or 2.2 percent, primarily due to increased NGLs volumes at Enogex partially offset by lower NGLs prices at Enogex, a decrease in accruals and the timing of ad valorem payments.

***Cash Flows***

| | | | | 2012 vs. 2011 | | 2011 vs. 2010 | |
|---|---|---|---|---|---|---|---|
| Year ended December 31 *(In millions)* | **2012** | 2011 | 2010 | $ Change | % Change | $ Change | % Change |
| Net cash provided from operating activities | **$ 1,046.1** | $ 833.9 | $ 782.5 | $ 212.2 | 25.4 % | $ 51.4 | 6.6% |
| Net cash used in investing activities | **(1,192.6)** | (1,395.8) | (846.1) | 203.2 | (14.6)% | (549.7) | 65.0% |
| Net cash provided from financing activities | **143.7** | 564.2 | 7.8 | (420.5) | (74.5)% | 556.4 | * |

* Percentage is greater than 100 percent.

**Operating Activities**

The increase of $212.2 million, or 25.4 percent, in net cash provided from operating activities in 2012 as compared to 2011 was primarily due to:

- higher fuel recoveries at OG&E in 2012 as compared to 2011;
- an increase in cash received in 2012 from transmission revenue and the recovery of investments including the Crossroads wind farm and smart grid partially offset by milder weather in 2012; and
- an increase in gathered volumes and NGLs volumes at Enogex during 2012 as compared to 2011 partially offset by lower natural gas and NGLs prices in 2012 as compared to 2011.

The increase of $51.4 million, or 6.6 percent, in net cash provided from operating activities in 2011 as compared to 2010 was primarily due to:

- lower fuel refunds at OG&E in 2011 as compared to 2010; and
- cash received in 2011 from an increase in billings to OG&E's customers due to warmer weather in OG&E's service territory in 2011;

These increases in net cash provided from operating activities was partially offset by income tax refunds received in 2010 related to a carry back of the 2008 tax loss resulting from a change in tax method of accounting for capitalization of repair expenditures and accelerated tax bonus depreciation.

**Investing Activities**

The decrease of $203.2 million, or 14.6 percent, in net cash used in investing activities in 2012 as compared to 2011 was primarily due to lower levels of capital expenditures in 2012 related to the Crossroads wind farm at OG&E and lower levels of capital expenditures related to gathering and processing expansion projects at Enogex.

The increase of $549.7 million, or 65.0 percent, in net cash used in investing activities in 2011 as compared to 2010 primarily related to higher levels of capital expenditures in 2011 related to various transmission projects and the Crossroads wind farm at OG&E and gathering and processing expansion projects at Enogex.

**Financing Activities**

The decrease of $420.5 million, or 74.5 percent, in net cash provided from financing activities in 2012 as compared to 2011 was primarily due to:

- lower contributions from the ArcLight group during 2012 as compared to 2011;
- higher borrowings under Enogex's revolving credit agreement during 2011; and
- repayments of Enogex's line of credit during 2012.

These decreases in net cash provided from financing activities were partially offset by an increase in short-term debt borrowings during 2012 as compared to 2011.

The increase of $556.4 million in net cash provided from financing activities in 2011 as compared to 2010 was primarily due to:

- repayment in 2010 of the remaining balance of Enogex LLC's $400 million 8.125% senior notes which matured on January 15, 2010;

- an increase in short-term debt borrowings in 2011 as compared to 2010;
- contributions from the noncontrolling interest partners in 2011;
- higher borrowings under Enogex LLC's revolving credit agreement in 2011; and
- a decrease in repayments of borrowings under Enogex LLC's revolving credit agreement in 2011 as compared to 2010.

***Future Capital Requirements and Financing Activities***

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and Enogex. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, hedging activities, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings.

**Capital Expenditures**

The Company's consolidated estimates of capital expenditures for the years 2013 through 2017 are shown in the following table. These capital expenditures represent the base maintenance capital expenditures (i.e., capital expenditures to maintain and operate the Company's businesses) plus capital expenditures for known and committed projects.

| *(In millions)* | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|
| OG&E Base Transmission | $ 65 | $ 50 | $ 50 | $ 50 | $ 50 |
| OG&E Base Distribution | 175 | 175 | 175 | 175 | 175 |
| OG&E Base Generation | 80 | 75 | 75 | 75 | 75 |
| OG&E Other | 15 | 15 | 15 | 15 | 15 |
| Total OG&E Base Transmission, Distribution, Generation and Other | 335 | 315 | 315 | 315 | 315 |
| OG&E Known and Committed Projects: | | | | | |
| Transmission Projects: | | | | | |
| Balanced Portfolio 3E Projects (A) | 205 | 25 | — | — | — |
| SPP Priority Projects (B) | 165 | 110 | — | — | — |
| SPP Integrated Transmission Projects (C) | 5 | 5 | — | 40 | 40 |
| Total Transmission Projects | 375 | 140 | — | 40 | 40 |
| Other Projects: | | | | | |
| Smart Grid Program | 25 | 25 | 10 | 10 | — |
| System Hardening | 15 | — | — | — | — |
| Environmental - low NOX burners | 30 | 20 | 25 | 20 | — |
| Total Other Projects | 70 | 45 | 35 | 30 | — |
| Total OG&E Known and Committed Projects | 445 | 185 | 35 | 70 | 40 |
| Total OG&E (D) | 780 | 500 | 350 | 385 | 355 |
| Enogex LLC Base Maintenance | 50 | 55 | 55 | 55 | 55 |
| Enogex LLC Known and Committed Projects: | | | | | |
| Western Oklahoma / Texas Panhandle Gathering Expansion | 380 | 180 | 140 | 80 | 65 |
| Other Gathering Expansion | 25 | 15 | 10 | 10 | 10 |
| Total Enogex LLC Known and Committed Projects | 405 | 195 | 150 | 90 | 75 |
| Total Enogex LLC (E) | 455 | 250 | 205 | 145 | 130 |
| OGE Energy | 10 | 10 | 10 | 10 | 10 |
| Total capital expenditures | $ 1,245 | $ 760 | $ 565 | $ 540 | $ 495 |

(A) Balanced Portfolio 3E includes three projects to be built by OG&E and includes: (i) construction of 135 miles of transmission line from OG&E's Seminole substation in a northeastern direction to OG&E's Muskogee substation at an estimated cost of $175 million for OG&E, which is expected to be in service by late 2013, (ii) construction of 96 miles of transmission line from OG&E's Woodward District Extra High Voltage substation in a southwestern direction to the Oklahoma/Texas Stateline to a companion transmission line to be built by Southwestern Public Service to its Tuco substation at an estimated cost of

$115 million for OG&E, which is expected to be in service by mid-2014 and (iii) construction of 39 miles of transmission line from OG&E's Sooner substation in an eastern direction to the Grand River Dam Authority Cleveland substation at an estimated cost of $45 million for OG&E, which was placed in service in February 2013.

(B) The Priority Projects consist of several transmission projects, two of which have been assigned to OG&E. The 345 kilovolt projects include: (i) construction of 99 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line to be built by Southwestern Public Service to its Hitchland substation in the Texas Panhandle at an estimated cost of $185 million for OG&E, which is expected to be in service by mid-2014 and (ii) construction of 77 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line at the Kansas border to be built by either Mid-Kansas Electric Company or another company assigned by Mid-Kansas Electric Company at an estimated cost of $150 million to OG&E, which is expected to be in service by late 2014. OG&E began construction on the Hitchland project in November 2012 and expects to begin construction on the Kansas project in June 2013.

(C) On January 31, 2012, the SPP approved the Integrated Transmission Plan Near Term and Integrated Transmission Plan 10-year projects. These plans include two projects to be built by OG&E: (i) construction of 47 miles of transmission line from OG&E's Gracemont substation in a northwestern direction to a companion transmission line to be built by American Electric Power to its Elk City substation at an estimated cost of $75 million for OG&E, which is expected to be in service by early 2018, and (ii) construction of 126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation in a southeastern direction to OG&E's Cimarron substation and construction of a new substation on this transmission line, the Mathewson substation, at an estimated cost of $210 million for OG&E, which is expected to be in service by early 2021. On April 9, 2012, OG&E received a notice to construct these projects from the SPP. On June 26, 2012, OG&E responded to the SPP that OG&E will construct the projects discussed above and is moving forward with more detailed cost estimates that must be reviewed and approved by the SPP. OG&E and American Electric Power are currently in discussions regarding how much of the 94 mile Elk City to Gracemont transmission line will be built by OG&E and American Electric Power. American Electric Power has argued for a larger portion of such transmission line than the traditional 50 percent split. The capital expenditures related to these projects are presented in the summary of capital expenditures for known and committed projects above.

(D) The capital expenditures above exclude any environmental expenditures associated with:

- Pollution control equipment related to controlling SO2 emissions under the regional haze requirements due to the uncertainty regarding the approach and timing for such pollution control equipment. The SO2 emissions standards in the EPA's FIP could require the installation of Dry Scrubbers or fuel switching. OG&E estimates that installing such Dry Scrubbers could cost more than $1.0 billion. The FIP is being challenged by OG&E and the state of Oklahoma. On June 22, 2012, OG&E was granted a stay of the FIP by the U.S. Court of Appeals for the Tenth Circuit, which delays the timing of required implementation of the SO2 emissions standards in the rule. The merits of the appeal have been fully briefed, and oral argument is scheduled to occur on March 6, 2013. Neither the outcome of the challenge to the FIP nor the timing of any required capital expenditures can be predicted with any certainty at this time, but such capital expenditures could be significant.
- Installation of control equipment for compliance with MATS by a deadline of April 16, 2015, with the possibility of a one-year extension. OG&E is currently planning to utilize activated carbon injection and low levels of dry sorbent injection at each of its five coal-fired units. Due to various uncertainties about the final design, the potential use of this technology relating to regional haze measures and the specifications for the control equipment, the resulting cost estimates currently range from $34 million to $72 million per unit.

OG&E is currently evaluating options to comply with environmental requirements. For further information, see "Environmental Laws and Regulations" below.

(E) These capital expenditures represent 100 percent of Enogex LLC's capital expenditures, of which a portion may be funded by the ArcLight group. Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. If necessary, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets and at Enogex LLC, will be evaluated based upon their impact upon achieving the Company's financial objectives. The capital expenditure projections related to Enogex LLC in the table above reflect base market conditions at February 27, 2013 and do not reflect the potential opportunity for a set of growth projects that could materialize. Also, if drilling activity declines in the future, this could reduce Enogex's capital expenditures in the table above.

**Contractual Obligations**

The following table summarizes the Company's contractual obligations at December 31, 2012. See the Company's Consolidated Statements of Capitalization and Note 16 of Notes to Consolidated Financial Statements for additional information.

| *(In millions)* | 2013 | 2014-2015 | 2016-2017 | After 2017 | Total |
|---|---|---|---|---|---|
| Maturities of long-term debt (A) | $ 0.2 | $ 550.4 | $ 235.4 | $ 2,070.1 | $ 2,856.1 |
| Operating lease obligations | | | | | |
| OG&E railcars | 3.2 | 5.5 | 27.3 | — | 36.0 |
| OG&E wind farm land leases | 2.0 | 4.2 | 4.5 | 51.2 | 61.9 |
| OGE Energy noncancellable operating lease | 0.3 | 1.6 | 1.6 | 0.7 | 4.2 |
| Enogex noncancellable operating leases | 5.2 | 7.2 | 4.1 | — | 16.5 |
| Total operating lease obligations | 10.7 | 18.5 | 37.5 | 51.9 | 118.6 |
| Other purchase obligations and commitments | | | | | |
| OG&E cogeneration capacity and fixed operation and maintenance payments | 87.9 | 170.3 | 162.5 | 315.3 | 736.0 |
| OG&E expected cogeneration energy payments | 58.6 | 134.3 | 168.3 | 468.7 | 829.9 |
| OG&E minimum fuel purchase commitments | 405.0 | 519.8 | — | — | 924.8 |
| OG&E expected wind purchase commitments | 57.5 | 116.9 | 120.6 | 838.0 | 1,133.0 |
| OG&E long-term service agreement commitments | 8.0 | 34.5 | 12.6 | 53.0 | 108.1 |
| EER commitments | 11.9 | 15.5 | 0.8 | — | 28.2 |
| Total other purchase obligations and commitments | 628.9 | 991.3 | 464.8 | 1,675.0 | 3,760.0 |
| Total contractual obligations | 639.8 | 1,560.2 | 737.7 | 3,797.0 | 6,734.7 |
| Amounts recoverable through fuel adjustment clause (B) | (524.3) | (776.5) | (316.2) | (1,306.7) | (2,923.7) |
| Total contractual obligations, net | $ 115.5 | $ 783.7 | $ 421.5 | $ 2,490.3 | $ 3,811.0 |

(A) Maturities of the Company's long-term debt during the next five years consist of $0.2 million, $300.2 million, $250.2 million, $110.2 million and $125.2 million in years 2013, 2014, 2015, 2016 and 2017, respectively.

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

OG&E also has 440 MWs of QF contracts to meet its current and future expected customer needs. OG&E will continue reviewing all of the supply alternatives to these QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates.

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

**Pension and Postretirement Benefit Plans**

At December 31, 2012, 42.3 percent of the Pension Plan investments were in listed common stocks with the balance primarily invested in U.S Government securities, bonds, debentures and notes, a commingled fund and a common collective trust as presented in Note 14 of Notes to Consolidated Financial Statements. In 2012, asset returns on the Pension Plan were 10.6 percent due to the gains in fixed income and equity investments. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline. During 2012 and 2011, OGE Energy made contributions to its Pension Plan of $35 million and $50 million, respectively, to help ensure that the Pension Plan maintains an adequate funded status. The level of funding is dependent on returns on plan assets and future discount rates. During 2013, OGE Energy expects to contribute up to $35 million to its Pension Plan. OGE Energy could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

The following table presents the status of the Company's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans at December 31, 2012 and 2011. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1 of Notes to Consolidated Financial Statements) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

| | Pension Plan | | Restoration of Retirement Income Plan | | Postretirement Benefit Plans | |
|---|---|---|---|---|---|---|
| December 31 *(In millions)* | **2012** | 2011 | **2012** | 2011 | **2012** | 2011 |
| Benefit obligations | **$ (747.1)** | $ (697.7) | **$ (14.5)** | $ (13.3) | **$ (301.0)** | $ (280.6) |
| Fair value of plan assets | **626.0** | 589.8 | **—** | — | **59.6** | 61.0 |
| Funded status at end of year | **$ (121.1)** | $ (107.9) | **$ (14.5)** | $ (13.3) | **$ (241.4)** | $ (219.6) |

**Common Stock Dividends**

The Company's dividend policy is reviewed by the Board of Directors at least annually and is based on numerous factors, including management's estimation of the long-term earnings power of its businesses. The Company's financial objective includes increasing the dividend to meet the Company's dividend payout objectives. The Company's target payout ratio is to pay out dividends no more than 60 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. At the Company's November 2012 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 $0.4175 per share from $0.3925 per share effective with the Company's first quarter 2013 dividend.

**Security Ratings**

| | Moody’s Investors Services | Standard & Poor's Ratings Services | Fitch Ratings |
|---|---|---|---|
| OG&E Senior Notes | A2 | BBB+ | A+ |
| Enogex LLC Notes | Baa3 | BBB- | BBB |
| OGE Energy Senior Notes | Baa1 | BBB | A- |
| OGE Energy Commercial Paper | P2 | A2 | F2 |

Access to reasonably priced capital is dependent in part on credit and security ratings. Generally, lower ratings lead to higher financing costs. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post collateral or letters of credit. In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Company's senior unsecured debt rating to a below investment grade rating, at December 31, 2012, the Company would have been required to post $0.2 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2012. In addition, the Company could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

On June 20, 2012, Fitch Ratings downgraded OGE Energy Corp.'s short-term debt rating from F1 to F2 and OGE Energy Corp.'s long-term debt issuer default rating from A to A-. All other ratings (by Fitch Ratings) at OG&E and Enogex remained unchanged and with a stable outlook. Fitch Ratings indicated that the downgrade at OGE Energy Corp. was primarily due to concerns related to the uncertainties associated with the environmental mandates at OG&E as well as Enogex's sensitivity to commodity prices and growth strategy with the ArcLight group.

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.

***2012 Capital Requirements, Sources of Financing, Purchase of Treasury Stock and Financing Activities***

Total capital requirements, consisting of capital expenditures and maturities of long-term debt, were $1,351.8 million and contractual obligations, net of recoveries through fuel adjustment clauses, were $112.8 million resulting in total net capital requirements and contractual obligations of $1,464.6 million in 2012, of which $12.9 million was to comply with environmental regulations. This compares to net capital requirements of $1,446.2 million and net contractual obligations of $111.1 million totaling $1,557.3 million in 2011, of which $6.9 million was to comply with environmental regulations.

In 2012, the Company's sources of capital were cash generated from operations, proceeds from the issuance of short-term debt, proceeds from Enogex's term loan agreement, proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan, funding for growth opportunities at Enogex through the ArcLight group and quarterly distributions from Enogex Holdings. 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 "Working Capital" for a discussion of significant changes in net working capital requirements as it pertains to operating cash flow and liquidity.

**Purchase of Treasury Stock**

In November 2012, the Company purchased 60,000 shares of its common stock at an average cost of $55.41 per share on the open market. These shares will be used to satisfy Enogex's portion of the Company's obligation to deliver shares of common stock related to long-term incentive payouts of earned performance units in 2013. The Company expects to purchase shares in the future to satisfy a portion of its obligation under its incentive plan.

**Enogex Term Loan Agreement**

On August 2, 2012, Enogex entered into a $250 million, three-year term loan agreement with a maturity date of August 2, 2015. The loan was used to fund capital expenditures and for working capital purposes.

**Potential Collateral Requirements**

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

On July 21, 2010, President Obama signed into law the Dodd-Frank Act. Among other things, the Dodd-Frank Act provides for a new regulatory regime for derivatives, including mandatory clearing of certain swaps and margin requirements. The Dodd-Frank Act contains provisions that should exempt certain derivatives end-users such as the Company from much of the clearing requirements. The regulations require that the decision on whether to use the end-user exception from mandatory clearing for derivative transactions be reviewed and approved by an "appropriate committee" of the Board of Directors. The scope of the margin requirements and their potential direct impact on the Company remain unclear because final rules have not been issued. Further, even if the Company qualifies for the end-user exception to clearing and margin requirements are not imposed on end-users, its derivative counterparties may be subject to new capital, margin and business conduct requirements as a result of the new regulations, which may increase the Company's transaction costs or make it more difficult to enter into derivative transactions on favorable terms. The Company's inability to enter into derivative transactions on favorable terms, or at all, could increase operating expenses and put the Company at increased exposure to risks of adverse changes in commodities prices. The impact of the provisions of the Dodd-Frank Act on the Company cannot be fully determined at this time due to uncertainty over forthcoming regulations and potential changes to the derivatives markets arising from new regulatory requirements.

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

**Short-Term Debt and Credit Facilities**

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The Company has revolving credit facilities totaling in the aggregate $1,550.0 million. These bank facilities can also be used as letter of credit facilities. The short-term debt balance was $430.9 million and $277.1 million at December 31, 2012 and 2011, respectively. The weighted-average interest rate on short-term debt at December 31, 2012 was 0.43 percent. The average balance of short-term debt in 2012 was $451.0 million at a weighted-average interest rate of 0.45 percent. The maximum month-end balance of short-term debt in 2012 was $608.2 million. At December 31, 2012, Enogex had no outstanding borrowings under its revolving credit agreement as compared to $150.0 million at December 31, 2011. As Enogex LLC's credit agreement matures on December 13, 2016, along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Consolidated Balance Sheets. At December 31, 2012, the Company had $1,116.9 million of net available liquidity under its revolving credit agreements. 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, 2013 and ending December 31, 2014. At December 31, 2012, the Company had $1.8 million in cash and cash equivalents. See Note 13 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

**Expected Issuance of Long-Term Debt**

OG&E expects to issue up to $250 million of long-term debt in the first half of 2013, depending on market conditions, to fund capital expenditures, repay short-term borrowings and for general corporate purposes.

**Common Stock**

The Company expects to issue between $12 million and $15 million of common stock in its Automatic Dividend Reinvestment and Stock Purchase Plan in 2013. See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

**Minimum Quarterly Distributions by Enogex Holdings**

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover OGE Energy's anticipated tax liabilities plus $12.5 million, to be distributed in proportion to each member's percentage ownership interest.

**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 for all Company segments includes the determination of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets) income taxes, contingency reserves, asset retirement obligations, fair value and cash flow hedges and the allowance for uncollectible accounts receivable. For the electric utility segment, the most significant judgment is also exercised in the valuation of regulatory assets and liabilities and unbilled revenues. For the natural gas transportation and storage segment and the natural gas gathering and processing segment, the most significant judgment is also exercised in the valuation of operating revenues, natural gas purchases, purchase and sale contracts, assets and depreciable lives of property, plant and equipment, amortization methodologies related to intangible assets and impairment assessments of goodwill. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's Audit Committee. The Company discusses its significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in Note 1 of Notes to Consolidated Financial Statements.

***Consolidated (including all Company segments)***

**Pension and Postretirement Benefit Plans**

The Company has a Pension Plan that covers a significant amount of the Company's employees hired before December 1, 2009. Also, effective December 1, 2009, the Company's Pension Plan is no longer being offered to employees hired on or after December 1, 2009. The Company also has defined benefit postretirement plans that cover a significant amount of its employees. Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and the level of funding. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized. The pension plan rate assumptions are shown in Note 14 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 | +/- 1 percent | +/- $6.3 million |
| Discount rate | +/- 0.25 percent | +/- $16.7 million |
| Contributions | +/- $10 million | +/- $10 million |

**Assessing Impairment of Long-Lived Assets (Including Intangible Assets) and Goodwill**

The Company assesses its long-lived assets, including intangible assets with finite useful lives, for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset's carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets 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. 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. In 2011, the Company recorded a pre-tax impairment loss of $5.0 million, of which $2.5 million was the noncontrolling interest portion (see Note 5 of Notes to Consolidated Financial Statements), related to the Atoka processing plant. The Company recorded no other material impairments in 2012, 2011 or 2010.

As a result of the gas gathering acquisitions in November 2011, Enogex recorded goodwill of $39.4 million. Enogex assesses its goodwill for impairment at least annually as of October 1 by comparing the fair value of the reporting unit with its book value, including goodwill. Enogex utilizes the income approach (generally accepted valuation approach) to estimate the fair value of the reporting unit, also giving consideration to alternative methods such as the market and cost approaches. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. Enogex performs its goodwill impairment testing at the natural gas gathering and processing segment reporting unit level. Enogex recorded no impairments of goodwill in 2012.

**Income Taxes**

The Company uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change.

The application of income tax law is complex. Laws and regulations in this area are voluminous and often ambiguous. Interpretations and guidance surrounding income tax laws and regulations change over time. Accordingly, it is necessary to make judgments regarding income tax exposure. As a result, changes in these judgments can materially affect amounts the Company recognized in its consolidated financial statements. Tax positions taken by the Company on its income tax returns that are recognized in the financial statements must satisfy a more likely than not recognition threshold, assuming that the position will be examined by taxing authorities with full knowledge of all relevant information.

**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 or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements.

Except as disclosed otherwise in this Form 10-K, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Notes 16 and 17 of Notes to Consolidated Financial Statements and Item 3 of Part I in this Form 10-K for a discussion of the Company's commitments and contingencies.

**Asset Retirement Obligations**

The Company has previously recorded asset retirement obligations that are being amortized over their respective lives ranging from three months to 74 years. The Company also has certain asset retirement obligations primarily related to Enogex's processing plants and compression sites that have not been recorded because the Company cannot determine when these obligations will be incurred. The inputs used in the valuation of asset retirement obligations include the assumed life of the asset placed into service, the average inflation rate, market risk premium, the credit-adjusted risk free interest rate and the timing of incurring costs related to the retirement of the asset.

**Hedging Policies**

The Company designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing operations and natural gas transportation and storage operations (operational gas hedges). The Company also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. 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. Enogex's cash flow hedges at December 31, 2012 mature by the end of the first quarter of 2013.

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

***Electric Utility Segment***

**Regulatory Assets and Liabilities**

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

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

**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, 2012, if the estimated usage or price used in the unbilled revenue calculation were to increase or decrease by one percent, this would cause a change in the unbilled revenues recognized of $0.3 million. At December 31, 2012 and 2011, Accrued Unbilled Revenues were $57.4 million and $59.3 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 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. Also, a portion of the uncollectible provision related to fuel is being recovered through the fuel adjustment clause. At December 31, 2012, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of $0.3 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 $2.6 million and $3.7 million at December 31, 2012 and 2011, respectively.

***Natural Gas Transportation and Storage and Natural Gas Gathering and Processing Segments***

**Operating Revenues**

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

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

Enogex records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. In August 2010, Enogex completed construction of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Aid in Construction payments of $36.4 million received in excess of construction costs were recognized as Deferred Revenues on the Company's Consolidated Balance Sheet and are being amortized on a straight-line basis of $1.2 million per year over the life of the related firm transportation service agreement under which service commenced in June 2011. Also, in August 2011, Enogex and one of its five largest customers entered into new agreements, effective July 1, 2011, relating to the customer's natural gas gathering and processing volumes on the Oklahoma portion of Enogex's system. As a result, Enogex has recorded $7.1 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2012, which are expected to be recognized based on the estimated average fee per MMBtu processed by the end of 2014. Enogex has also recorded $1.5 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2012 in connection with other gathering and processing agreements.

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

**Natural Gas Purchases**

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

**Purchase and Sale Contracts**

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

In nearly all cases, independent market prices are obtained and compared to the values used in determining the fair value. 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, 2012, unrealized mark-to-market losses were $0.2 million, none of which were calculated utilizing models. At December 31, 2012, 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.

**Valuation of Assets**

The application of business combination and impairment accounting requires Enogex to use significant estimates and assumptions in determining the fair value of assets and liabilities. The acquisition method of accounting for business combinations requires Enogex to estimate the fair value of assets acquired and liabilities assumed to allocate the proper amount of the purchase price consideration between goodwill and the assets that are depreciated and amortized. Enogex records intangible assets separately from goodwill and amortizes intangible assets with finite lives over their estimated useful life as determined by management. Enogex does not amortize goodwill but instead annually assesses goodwill for impairment.

In 2011 and 2012, Enogex completed gas gathering acquisitions accounted for as business combinations as discussed in Note 3 of Notes to Consolidated Financial Statements. As part of these acquisitions, Enogex has engaged the services of a third-party valuation expert to assist it in determining the fair value of the acquired assets and liabilities, including goodwill; however, the ultimate determination of those values is the responsibility of Enogex's management. Enogex bases its estimates on assumptions believed to be reasonable, but which are inherently uncertain. These valuations require the use of management's assumptions, which would not reflect unanticipated events and circumstances that may occur.

**Depreciable Lives of Property, Plant and Equipment and Amortization Methodologies Related to Intangible Assets**

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. Intangible assets are amortized on a straight-line basis over their useful lives using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

**Natural Gas Inventory**

Natural gas inventory is held by Enogex, through its transportation and storage business, to provide operational support for its pipeline deliveries and to manage its leased storage capacity. In an effort to mitigate market price exposures, Enogex may enter into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is valued using moving average cost and is recorded at the lower of cost or market. As part of its asset management activity, Enogex injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. During the years ended December 31, 2012, 2011 and 2010, Enogex recorded write-downs to market value related to natural gas storage inventory of $5.5 million, $4.8 million and $0.3 million, respectively. The amount of Enogex's natural gas inventory was $16.5 million and $23.7 million at December 31, 2012 and 2011, respectively. The cost of gas associated with sales of natural gas storage inventory is presented in Cost of Goods Sold on the Consolidated Statements of Income.

**Allowance for Uncollectible Accounts Receivable**

The allowance for uncollectible accounts receivable for Enogex is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when Enogex believes the collection of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable 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 Enogex's natural gas transportation and storage and natural gas gathering and processing segments was less than $0.1 million at December 31, 2012 and 2011.

**Accounting Pronouncements**

See Note 2 of Notes to Consolidated Financial Statements for discussion of current accounting pronouncements that are applicable to the Company.

**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 or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. At the present time, based on currently available information, except as disclosed otherwise in this Form 10-K, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Notes 16 and 17 of Notes to Consolidated Financial Statements and Item 3 of Part I in this Form 10-K for a discussion of the Company's commitments and contingencies.

**Environmental Laws and Regulations**

The activities of OG&E and Enogex are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way it can handle or dispose of their wastes, requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. OG&E and Enogex believe that their operations are in substantial compliance with current Federal, state and local environmental standards.

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

OG&E expects that significant future capital expenditures necessary to comply with the environmental laws and regulations discussed below 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.

It is estimated that OG&E's and Enogex's total expenditures to comply with environmental laws, regulations and requirements for 2013 will be $63.0 million and $6.4 million, respectively, of which $45.3 million and $0.7 million, respectively, are for capital expenditures. It is estimated that OG&E's and Enogex's total expenditures to comply for environmental laws, regulations and requirements for 2014 will be $37.7 million and $6.3 million, respectively, of which $19.2 million and $0.5 million, respectively, are for capital expenditures. The amounts for OG&E above include capital expenditures for low NOX burners and exclude certain other capital expenditures as discussed in the capital expenditures table and related footnote D in "Future Capital Requirements and Financing Activities" above. The Company's management believes that all of its operations are in substantial compliance with current Federal, state and local environmental standards. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

**Air**

***Federal Clean Air Act Overview***

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

***Regional Haze Control Measures***

On June 15, 2005, the EPA issued final amendments to its 1999 regional haze rule. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. The regional haze rule is intended to protect visibility in certain national parks and wilderness areas throughout the United States. In Oklahoma, the Wichita Mountains are the only area covered under the rule. However, Oklahoma's impact on parks in other states must also be evaluated.

As required by the Federal regional haze rule, the state of Oklahoma evaluated the installation of BART to reduce emissions that cause or contribute to regional haze from certain sources within the state that were built between 1962 and 1977. Certain of OG&E’s units at the Horseshoe Lake, Seminole, Muskogee and Sooner generating stations were evaluated for BART. On February 18, 2010, Oklahoma submitted its SIP to the EPA, which set forth the state's plan for compliance with the Federal regional haze rule. The SIP was subject to the EPA's review and approval.

The Oklahoma SIP included requirements for reducing emissions of NOX and SO2 from OG&E's seven BART-eligible units at the Seminole, Muskogee and Sooner generating stations. The SIP also included a waiver from BART requirements for all eligible units at the Horseshoe Lake generating station based on air modeling that showed no significant impact on visibility in nearby national parks and wilderness areas. The SIP concluded that BART for reducing NOX emissions at all of the subject units should be the installation of low NOX burners with overfire air (flue gas recirculation was also required on two of the units) and set forth associated NOX emission rates and limits. OG&E preliminarily estimates that the total capital cost of installing and operating these NOX controls on all covered units, based on recent industry experience and past projects, will be approximately $95 million. With respect to SO2 emissions, the SIP included an agreement between the Oklahoma Department of Environmental Quality and OG&E that established BART for SO2 control at the four affected coal-fired units located at OG&E's Sooner and Muskogee generating stations as the continued use of low sulfur coal (along with associated emission rates and limits). The SIP specifically rejected the installation and operation of Dry Scrubbers as BART for SO2 control from these units because the state determined that Dry Scrubbers were not cost effective on these units.

On December 28, 2011, the EPA issued a final rule in which it rejected portions of the Oklahoma SIP and issued a FIP in their place. While the EPA accepted Oklahoma's BART determination for NOX in the final rule, it rejected Oklahoma's SO2 BART determination with respect to the four coal-fired units at the Sooner and Muskogee generating stations. The EPA is instead requiring that OG&E meet an SO2 emission rate of 0.06 pounds per MMBtu within five years. OG&E could meet the proposed standard by either installing and operating Dry Scrubbers or fuel switching at the four affected units. OG&E estimates that installing Dry Scrubbers on these units would include capital costs to OG&E of more than $1.0 billion. OG&E and the state of Oklahoma filed an administrative stay request with the EPA on February 24, 2012. The EPA has not yet responded to this request. OG&E and other parties also filed a petition for review of the FIP in the U.S. Court of Appeals for the Tenth Circuit on February 24, 2012 and a stay request on April 4, 2012. On June 22, 2012, the U.S. Court of Appeals for the Tenth Circuit granted the stay request. The stay will remain in place until a decision on the petition for review is complete, which will delay the implementation of the regional haze rule in Oklahoma. The merits of the appeal have been fully briefed and oral argument is scheduled to occur on March 6, 2013. Neither the outcome of the appeal nor the timing of any required expenditures for pollution control equipment can be predicted with any certainty at this time.

***Cross-State Air Pollution Rule***

On July 7, 2011, the EPA finalized its Cross-State Air Pollution Rule to replace the former Clean Air Interstate Rule that was remanded by a Federal court as a result of legal challenges. The final rule would require 27 states to reduce power plant emissions that contribute to ozone and particulate matter pollution in other states. On December 27, 2011, the EPA published a supplemental rule, which would make six additional states, including Oklahoma, subject to the Cross-State Air Pollution Rule for NOX emissions during the ozone-season from May 1 through September 30. Under the rule, OG&E would have been required to reduce ozone-season NOX emissions from its electrical generating units within the state beginning in 2012. The Cross-State Air Pollution Rule was challenged in court by numerous states and power generators. On December 30, 2011, the U.S. Court of Appeals issued a stay of the rule, which includes the supplemental rule, pending a decision on the merits. By order dated August 21, 2012, the U.S. Court of Appeals vacated the Cross-State Air Pollution Rule and ordered the EPA to promulgate a replacement rule. On January 25, 2013, the U.S. Court of Appeals denied the EPA's request for an en banc reconsideration of the court's decision vacating the rule. OG&E cannot predict the outcome of such challenges.

***Hazardous Air Pollutants Emission Standards***

On April 16, 2012, regulations governing emissions of certain hazardous air pollutants from electric generating units were published as the final MATS rule. This rule includes numerical standards for particulate matter (as a surrogate for toxic metals), hydrogen chloride and mercury emissions from coal-fired boilers. In addition, the regulations include work practice standards for dioxins and furans. Compliance is required within three years after the effective date of the rule with the possibility of a one-year extension. To comply with this rule, OG&E is currently planning to utilize activated carbon injection and low levels of dry sorbent injection at each of its five coal-fired units. Due to various uncertainties about the final design, the potential use of this technology relating to regional haze measures and the specifications for the control equipment, the resulting cost estimates currently range from $34 million to $72 million per unit. OG&E is evaluating the results of field testing to finalize cost estimates and implementation schedules. The final MATS rule has been appealed by several parties. OG&E is not a party to the appeals and cannot predict the outcome of any such appeals.

***Notice of Violation***

In July 2008, OG&E received a request for information from the EPA regarding Federal Clean Air Act compliance at OG&E's Muskogee and Sooner generating plants. In recent years, the EPA has issued similar requests to numerous other electric utilities seeking to determine whether various maintenance, repair and replacement projects should have required permits under the Federal Clean Air Act's new source review process. In January 2012, OG&E received a supplemental request for an update of the previously provided information and for some additional information not previously requested. On May 1, 2012, OG&E responded to the EPA's supplemental request for information. OG&E believes it has acted in full compliance with the Federal Clean Air Act and new source review process and is cooperating with the EPA. On April 26, 2011, the EPA issued a notice of violation alleging that 13 projects occurred at OG&E's Muskogee and Sooner generating plants between 1993 and 2006 without the required new source review permits. The notice of violation also alleges that OG&E's visible emissions at its Muskogee and Sooner generating plants are not in accordance with applicable new source performance standards. OG&E has met with the EPA regarding the notice but cannot predict at this time what, if any, further actions may be necessary as a result of the notice. The EPA could seek to require OG&E to install additional pollution control equipment and pay fines and significant penalties as a result of the allegations in the notice of violation. Section 113 of the Federal Clean Air Act (along with the Federal Civil Penalties Inflation Adjustment Act of 1996) provides for civil penalties as much as $37,500 per day for each violation. The cost of any required pollution control equipment could also be significant.

*National Ambient Air Quality Standards*

The EPA is required to set NAAQS for certain pollutants considered to be harmful to public health or the environment. The Clean Air Act requires the EPA to review each NAAQS every five years. As a result of these reviews, the EPA periodically has taken action to adopt more stringent NAAQS for those pollutants. If any areas of Oklahoma were to be designated as not attaining the NAAQS for a particular pollutant, the Company could be required to install additional emission controls on its facilities to help the state achieve attainment with the NAAQS. As of the end of 2012, no areas of Oklahoma had been designated as non-attainment for pollutants that are likely to affect the Company's operations. Several processes are under way to designate areas in Oklahoma as attaining or not attaining revised NAAQS. The Company is monitoring those processes and their possible impact on its operations but, at this time, cannot determine with any certainty whether they will cause a material impact to the Company's financial results.

*Acid Rain Program*

The Federal Clean Air Act includes an Acid Rain Program. The goal of the Acid Rain Program is to achieve environmental and public health benefits through reductions in SO2 and NOX emissions, which are the primary causes of acid rain. To achieve this goal, the program employs both traditional and market-based approaches for controlling air pollution.

The Acid Rain Program introduces an allowance trading system that uses the free market to reduce pollution. Under this system, affected utility units are allocated allowances based on their historic fuel consumption and a specific emissions rate. Each allowance permits a unit to emit one ton of SO2 from the chimney during or after a specified year. For each ton of SO2 emitted in a given year, one allowance is retired, that is, it can no longer be used. Allowances may be bought, sold or banked.

During Phase II of the program (now in effect), the Federal Clean Air Act set a permanent ceiling (or cap) of 8.95 million total annual allowances allocated to utilities. This cap firmly restricts emissions and ensures that environmental benefits will be achieved and maintained. Due to OG&E's earlier decision to burn low sulfur coal, these restrictions have had no significant financial impact.

The Acid Rain Program also focuses on one set of sources that emit NOX, coal-fired electric utility boilers. As with the SO2 emission reduction requirements, the NOX program was implemented in two phases, beginning in 1996 and 2000. The NOX program embodies many of the same principles of the SO2 trading program. However, it does not cap NOX emissions as the SO2 program does, nor does it utilize an allowance trading system.

Emission limitations for NOX focus on the emission rate to be achieved (expressed in pounds of NOX per MMBtu of heat input). In general, two options for compliance with the emission limitations are provided: compliance with an individual emission rate for a boiler; or averaging of emission rates over two or more units to meet an overall emission rate limitation.

Since becoming subject to the Acid Rain Program, OG&E has met all obligations and limitations requirements.

*Climate Change and Greenhouse Gas Emissions*

There is continuing discussion and evaluation of possible global climate change in certain regulatory and legislative arenas. The focus is generally on emissions of greenhouse gases, including carbon dioxide, sulfur hexafluoride and methane, and whether these emissions are contributing to the warming of the Earth's atmosphere. There are various international agreements that restrict greenhouse gas emissions, but none of them have a binding effect on sources located in the United States. The U.S. Congress has not passed legislation to reduce emissions of greenhouse gases and the future prospects for any such legislation are uncertain, but the EPA has existing authority under the Clean Air Act to regulate greenhouse gas emissions from stationary sources. Several states have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Oklahoma, Arkansas and Texas are not among them. 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 the Company's facilities, this could result in significant additional compliance costs that would affect the Company’s future financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

Following from the Supreme Court's interpretation of the Clean Air Act's applicability to greenhouse gases in Massachusetts v. EPA, the EPA has proposed regulations for new power plants. In 2010, the EPA also issued a final rule that makes certain existing sources subject to permitting requirements for greenhouse gas emissions. This rule requires sources that emit greater than 100,000 tons per year of greenhouse gases to obtain a permit for those emissions, even if they are not otherwise required to obtain a new or modified permit. Such sources that undergo construction or modification may have to install best available control technology to control greenhouse gas emissions. Although these rules currently do not have a material impact on the Company's existing facilities, they ultimately could result in significant changes to the Company's operations, significant capital expenditures by the Company and a significant increase in the Company's cost of conducting business.

In 2009, the EPA adopted a comprehensive national system for reporting emissions of carbon dioxide and other greenhouse gases produced by major sources in the United States. The reporting requirements apply to large direct emitters of greenhouse gases with emissions equal to or greater than a threshold of 25,000 metric tons per year, which includes certain OG&E and Enogex facilities. OG&E also reports quarterly its carbon dioxide emissions from generating units subject to the Federal Acid Rain Program. OG&E and Enogex have submitted the reports required by the applicable reporting rules.

The Company is continuing to review and evaluate available options for reducing, avoiding, offsetting or sequestering its greenhouse gas emissions. OG&E is a partner in the EPA Sulfur Hexafluoride Voluntary Reduction Program. Enogex is a partner in the EPA Natural Gas STAR Program, a voluntary program to reduce methane emissions.

The Company also seeks to utilize renewable energy sources that do not emit greenhouse gases. OG&E's service territory is in central Oklahoma and borders one of the nation's best wind resource areas. The Company has leveraged its advantageous geographic position to develop renewable energy resources and transmission to deliver the renewable energy. The SPP has begun to authorize the construction of transmission lines capable of bringing renewable energy out of the wind resource area in western Oklahoma, the Texas Panhandle and western Kansas to load centers by planning for more transmission to be built in the area. In addition to significantly increasing overall system reliability, these new transmission resources should provide greater access to additional wind resources that are currently constrained due to existing transmission delivery limitations.

***Endangered Species***

Certain Federal laws, including the Bald and Golden Eagle Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which the Company conducts operations, or if additional species in those areas become subject to protection, the Company’s operations and development projects, particularly transmission, wind or pipeline projects, could be restricted or delayed, or the Company could be required to implement expensive mitigation measures. The U.S. Fish and Wildlife Service announced a proposed rule to list the lesser prairie chicken as threatened on November 30, 2012. A final decision regarding listing is anticipated to be completed by September 30, 2013. Although the lesser prairie chicken and its habitat are located in potential development areas of the Company, the impact of a final decision to list this species as threatened cannot be determined at this time.

**Waste**

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

For OG&E, these laws impose strict "cradle to grave" requirements on generators regarding their treatment, storage and disposal of hazardous waste. OG&E routinely generates small quantities of hazardous waste throughout its system and occasional larger quantities from periodic power generation related activities. These wastes are treated, stored and disposed at facilities that are permitted to manage them.

In June 2010, the EPA proposed new rules under Federal Resource Conservation and Recovery Act of 1976 that could alter the classification of OG&E's coal-fired power plants as conditionally exempt hazardous waste generators and make the management of coal ash more costly. The extent to which the EPA intends to regulate coal ash is uncertain due to the fact that the new rules propose to regulate coal ash as a hazardous waste or as a nonhazardous solid waste. In November 2010, OG&E submitted written comments opposing the regulation of coal ash as a hazardous waste while supporting its regulation as a nonhazardous waste. The EPA continues to consider numerous comments received on the proposal and has stated that no definitive timetable for issuing a final rule regarding the regulation of coal ash can be provided.

The Company has sought and will continue to seek pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2012, the Company obtained refunds of $6.4 million from the recycling of scrap metal, salvaged transformers and used transformer oil. 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.

For Enogex, the Federal Resource Conservation and Recovery Act of 1976 currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. However, these oil and gas exploration and production wastes may still be regulated under state law or the less stringent solid waste requirements of the Federal Resource Conservation and Recovery Act of 1976. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to the Federal Resource Conservation and Recovery Act of 1976 or comparable state law requirements.

**Water**

OG&E's and Enogex's operations are subject to the Federal Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and Federal waters. The discharge of pollutants, including discharges resulting from a spill or leak, is prohibited unless authorized by a permit or other agency approval. The Federal Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Existing cooling water intake structures are regulated under the Federal Clean Water Act to minimize their impact on the environment.

With respect to cooling water intake structures, Section 316(b) of the Federal Clean Water Act requires that their location, design, construction and capacity reflect the best available technology for minimizing their adverse environmental impact via the impingement and entrainment of aquatic organisms. In March 2011, the EPA proposed rules to implement Section 316(b). On August 18, 2011, OG&E filed comments with the EPA on the proposed rules. In June 2012, the EPA published a Notice of Data Availability requesting additional comments on a number of impingement mortality-related issues based on new information received during the initial public comment period. On July 11, 2012, OG&E filed comments regarding the Notice of Data Availability. In July 2012, the EPA entered into a settlement agreement in a pending litigation matter, which extended the deadline by which the proposed rules will be finalized to June 2013. In the interim, the state of Oklahoma requires OG&E to implement best management practices related to the operation and maintenance of its existing cooling water intake structures as a condition of renewing its discharge permits. Once the EPA promulgates the final rules, OG&E may incur additional capital and/or operating costs to comply with them. The costs of complying with the final water intake standards are not currently determinable, but could be significant.

**Site Remediation**

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 and comparable state laws impose liability, without regard to the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Because OG&E and Enogex utilize various products and generate wastes that are considered hazardous substances for purposes of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, OG&E and Enogex could be subject to liability for the costs of cleaning up and restoring sites where those substances have been released to the environment. At this time, it is not anticipated that any associated liability will cause a significant impact to OG&E or Enogex.

For a further discussion regarding contingencies relating to environmental laws and regulations, see Note 16 of Notes to Consolidated Financial Statements.

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

Market risks are, in most cases, risks that are actively traded in a marketplace and have been well studied in regards to quantification. Market risks include, but are not limited to, changes in interest rates and commodity prices. The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt and commercial paper. The Company is exposed to commodity prices in its operations.

***Risk Committee and Oversight***

Management monitors market risks using a risk committee structure. The Board of Directors appoints the Chief Risk Officer of the Company. The Chief Risk Officer serves as chairman of the Company's Risk Oversight Committee, which consists primarily of corporate officers, and is responsible for the overall development, implementation and enforcement of strategies and policies for all market risk management activities of the Company. This committee's emphasis is a holistic perspective of risk measurement and policies targeting the Company's overall financial performance. On a quarterly basis, the Risk Oversight Committee, through the Chief Risk Officer, reports to the Audit Committee of the Company's Board of Directors on the Company's risk profile affecting anticipated financial results, including any significant risk issues.

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

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

***Risk Policies***

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

***Interest Rate Risk***

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

The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities or by calculating the net present value of the monthly payments discounted by the Company's current borrowing rate. The following table shows the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

| Year ended December 31 *(Dollars in millions)* | 2013 | 2014 | 2015 | 2016 | 2017 | Thereafter | Total | 12/31/12 Fair Value |
|---|---|---|---|---|---|---|---|---|
| Fixed-rate debt (A) | | | | | | | | |
| Principal amount | $ 0.2 | $ 300.2 | $ 0.2 | $ 110.2 | $ 125.2 | $ 1,934.7 | $ 2,470.7 | $ 3,011.3 |
| Weighted-average interest rate | 2.71% | 6.25% | 2.71% | 5.15% | 6.49% | 6.38% | 6.31% | |
| Variable-rate debt (B) | | | | | | | | |
| Principal amount | $ — | $ — | $ 250.0 | $ — | $ — | $ 135.4 | $ 385.4 | $ 385.4 |
| Weighted-average interest rate | —% | —% | 1.72% | —% | —% | 0.24% | 1.20% | |

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

(B) A hypothetical change of 100 basis points in the underlying variable interest rate incurred by the Company would change interest expense by $3.9 million annually.

***Commodity Price Risk***

Commodity price risk is present in the Company's activities because changes in the prices of natural gas, NGLs and NGLs processing spreads have a direct effect on the compensation the Company receives for operating some of its assets. These prices are subject to fluctuations resulting from changes in supply and demand. To partially reduce commodity price risk, the Company utilizes risk mitigation tools such as default processing fees and ethane rejection capabilities to protect its downside exposure while maintaining its upside potential. Additionally, the Company utilizes derivatives and other forward transactions to mitigate the effects these market fluctuations have on the Company's operating income. Because the commodities covered by these transactions 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 commodity price risk. 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 positions; therefore, the value of positions is a summation of the forecasted values calculated for each commodity based upon internally generated forward price curves. Commodity price risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent decline in quoted market prices. The result of this analysis, which may differ from actual results, reflects net commodity price risk to be $21.6 million at December 31, 2012. This amount represents the Company's exposure, net of the ArcLight group's proportional share.

**Item 8. Financial Statements and Supplementary Data.**

## OGE ENERGY CORP.
## CONSOLIDATED STATEMENTS OF INCOME

| Year ended December 31 *(In millions except per share data)* | **2012** | 2011 | 2010 |
|---|---|---|---|
| OPERATING REVENUES | | | |
| Electric Utility operating revenues | **$ 2,141.2** | $ 2,211.5 | $ 2,109.9 |
| Natural Gas Midstream Operations operating revenues | **1,530.0** | 1,704.4 | 1,607.0 |
| Total operating revenues | **3,671.2** | 3,915.9 | 3,716.9 |
| COST OF GOODS SOLD (exclusive of depreciation and amortization shown below) | | | |
| Electric Utility cost of goods sold | **819.0** | 966.0 | 952.6 |
| Natural Gas Midstream Operations cost of goods sold | **1,099.7** | 1,311.9 | 1,234.8 |
| Total cost of goods sold | **1,918.7** | 2,277.9 | 2,187.4 |
| Gross margin on revenues | **1,752.5** | 1,638.0 | 1,529.5 |
| OPERATING EXPENSES | | | |
| Other operation and maintenance | **601.5** | 581.2 | 549.8 |
| Depreciation and amortization | **371.0** | 307.1 | 291.3 |
| Impairment of assets | **0.4** | 6.3 | 1.1 |
| Gain on insurance proceeds | **(7.5)** | (3.0) | — |
| Taxes other than income | **110.2** | 99.7 | 93.4 |
| Total operating expenses | **1,075.6** | 991.3 | 935.6 |
| OPERATING INCOME | **676.9** | 646.7 | 593.9 |
| OTHER INCOME (EXPENSE) | | | |
| Interest income | **0.6** | 0.5 | — |
| Allowance for equity funds used during construction | **6.2** | 20.4 | 11.4 |
| Other income | **17.0** | 19.3 | 13.7 |
| Other expense | **(16.5)** | (21.7) | (17.9) |
| Net other income | **7.3** | 18.5 | 7.2 |
| INTEREST EXPENSE | | | |
| Interest on long-term debt | **158.9** | 146.1 | 139.3 |
| Allowance for borrowed funds used during construction | **(3.5)** | (10.4) | (5.5) |
| Interest on short-term debt and other interest charges | **8.7** | 5.2 | 5.9 |
| Interest expense | **164.1** | 140.9 | 139.7 |
| INCOME BEFORE TAXES | **520.1** | 524.3 | 461.4 |
| INCOME TAX EXPENSE | **135.1** | 160.7 | 161.0 |
| NET INCOME | **385.0** | 363.6 | 300.4 |
| Less: Net income attributable to noncontrolling interests | **30.0** | 20.7 | 5.1 |
| NET INCOME ATTRIBUTABLE TO OGE ENERGY | **$ 355.0** | $ 342.9 | $ 295.3 |
| BASIC AVERAGE COMMON SHARES OUTSTANDING | **98.6** | 97.9 | 97.3 |
| DILUTED AVERAGE COMMON SHARES OUTSTANDING | **99.1** | 99.2 | 98.9 |
| BASIC EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS | **$ 3.60** | $ 3.50 | $ 3.03 |
| DILUTED EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS | **$ 3.58** | $ 3.45 | $ 2.99 |
| DIVIDENDS DECLARED PER COMMON SHARE | **$ 1.5950** | $ 1.5175 | $ 1.4625 |

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

**OGE ENERGY CORP.**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| Year ended December 31 *(In millions)* | **2012** | 2011 | 2010 |
|---|---|---|---|
| Net income | **$ 385.0** | $ 363.6 | $ 300.4 |
| Other comprehensive income (loss), net of tax | | | |
| Pension Plan and Restoration of Retirement Income Plan: | | | |
| Amortization of deferred net loss, net of tax of $1.7, $1.4 and $1.2, respectively | **3.0** | 2.5 | 1.3 |
| Net gain (loss) arising during the period, net of tax of ($5.6), ($6.7) and $4.4, respectively | **(10.2)** | (13.5) | 7.6 |
| Amortization of prior service cost, net of tax of $0.2, $0.2 and $0.1, respectively | **0.2** | 0.4 | 0.2 |
| Postretirement plans: | | | |
| Amortization of deferred net loss, net of tax of ($1.1), ($1.6) and $0.6, respectively | **2.0** | 1.8 | 1.2 |
| Net loss arising during the period, net of tax of ($1.1), ($3.1) and ($2.4), respectively | **(2.3)** | (3.6) | (4.1) |
| Amortization of deferred net transition obligation, net of tax of $0.1, $0.1 and $0.1, respectively | **0.1** | 0.2 | 0.1 |
| Amortization of prior service cost, net of tax of ($1.0), ($1.6) and $0.1, respectively | **(1.8)** | (1.8) | — |
| Prior service credit arising during the period, net of tax of $0, $9.5 and $0, respectively | **—** | 10.8 | — |
| Deferred commodity contracts hedging (gains) losses reclassified in net income, net of tax of ($1.6), $12.6 and $9.9, respectively | **(3.6)** | 27.6 | 18.5 |
| Deferred commodity contracts hedging gains (losses), net of tax of $0.1, ($1.7) and ($8.5), respectively | **0.4** | (4.8) | (16.3) |
| Amortization of deferred interest rate swap hedging losses, net of tax of $0.2, $0.2 and $0.2, respectively | **0.2** | 0.3 | 0.2 |
| Other comprehensive income (loss), net of tax | **(12.0)** | 19.9 | 8.7 |
| Comprehensive income (loss) | **373.0** | 383.5 | 309.1 |
| Less: Comprehensive income attributable to noncontrolling interest for sale of equity investment | **(0.5)** | (3.2) | (6.2) |
| Less: Comprehensive income attributable to noncontrolling interests | **27.0** | 24.2 | 5.5 |
| Total comprehensive income attributable to OGE Energy | **$ 346.5** | $ 362.5 | $ 309.8 |

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

**OGE ENERGY CORP.**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

| Year ended December 31 *(In millions)* | **2012** | 2011 | 2010 |
|---|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net income | **$ 385.0** | $ 363.6 | $ 300.4 |
| Adjustments to reconcile net income to net cash provided from operating activities | | | |
| Depreciation and amortization | **374.8** | 307.7 | 291.3 |
| Impairment of assets | **0.4** | 6.3 | 1.1 |
| Deferred income taxes and investment tax credits, net | **143.7** | 166.0 | 146.4 |
| Allowance for equity funds used during construction | **(6.2)** | (20.4) | (11.4) |
| (Gain) loss on disposition and abandonment of assets | **4.2** | (2.7) | — |
| Gain on insurance proceeds | **(7.5)** | (3.0) | — |
| Stock-based compensation | **(2.6)** | 7.8 | 7.4 |
| Excess tax benefit on stock-based compensation | **—** | — | (0.7) |
| Price risk management assets | **3.3** | (1.7) | 3.9 |
| Price risk management liabilities | **(4.6)** | 19.0 | 8.5 |
| Regulatory assets | **20.3** | 14.0 | 24.1 |
| Regulatory liabilities | **(14.8)** | (1.9) | (12.4) |
| Other assets | **(6.9)** | (7.6) | 6.3 |
| Other liabilities | **(14.3)** | (37.4) | (37.0) |
| Change in certain current assets and liabilities | | | |
| Accounts receivable, net | **27.1** | (48.0) | 11.9 |
| Accrued unbilled revenues | **1.9** | (2.5) | 0.4 |
| Income taxes receivable | **1.1** | (3.6) | 153.0 |
| Fuel, materials and supplies inventories | **13.7** | 54.2 | (45.2) |
| Gas imbalance assets | **(7.2)** | 0.7 | 0.7 |
| Fuel clause under recoveries | **1.8** | (0.8) | (0.7) |
| Other current assets | **(4.7)** | (7.2) | (5.9) |
| Accounts payable | **25.1** | 34.5 | 59.2 |
| Gas imbalance liabilities | **(4.8)** | 3.1 | (5.3) |
| Fuel clause over recoveries | **101.5** | (22.2) | (157.6) |
| Other current liabilities | **15.8** | 16.0 | 44.1 |
| Net Cash Provided from Operating Activities | **1,046.1** | 833.9 | 782.5 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | |
| Capital expenditures (less allowance for equity funds used during construction) | **(1,150.6)** | (1,270.4) | (879.9) |
| Acquisition of gathering assets | **(78.6)** | (200.4) | — |
| Proceeds from sale of assets | **1.5** | 18.0 | 2.3 |
| Proceeds from insurance | **7.6** | 7.4 | — |
| Reimbursement of capital expenditures | **27.5** | 49.6 | 31.5 |
| Net Cash Used in Investing Activities | **(1,192.6)** | (1,395.8) | (846.1) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Proceeds from long-term debt | **250.0** | 246.3 | 246.2 |
| Increase (decrease) in short-term debt | **153.8** | 132.1 | (30.0) |
| Contributions from noncontrolling interest partners | **46.2** | 216.4 | 183.2 |
| Issuance of common stock | **14.3** | 14.8 | 16.9 |
| Proceeds from line of credit | **—** | 150.0 | 115.0 |
| Retirement of long-term debt | **—** | — | (289.2) |
| Excess tax benefit on stock-based compensation | **—** | — | 0.7 |
| Payment of long-term debt | **(0.1)** | — | — |
| Purchase of treasury stock | **(3.4)** | (6.2) | — |
| Distributions to noncontrolling interest partners | **(12.6)** | (17.4) | (4.0) |
| Repayment of line of credit | **(150.0)** | (25.0) | (90.0) |
| Dividends paid on common stock | **(154.5)** | (146.8) | (141.0) |
| Net Cash Provided from Financing Activities | **143.7** | 564.2 | 7.8 |
| NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS | **(2.8)** | 2.3 | (55.8) |
| CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD | **4.6** | 2.3 | 58.1 |
| CASH AND CASH EQUIVALENTS AT END OF PERIOD | **$ 1.8** | $ 4.6 | $ 2.3 |

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

**OGE ENERGY CORP.**
**CONSOLIDATED BALANCE SHEETS**

| December 31 *(In millions)* | **2012** | 2011 |
|---|---|---|
| **ASSETS** | | |
| CURRENT ASSETS | | |
| Cash and cash equivalents | **$ 1.8** | $ 4.6 |
| Accounts receivable, less reserve of $2.6 and $3.8, respectively | **295.3** | 322.5 |
| Accrued unbilled revenues | **57.4** | 59.3 |
| Income taxes receivable | **7.2** | 8.3 |
| Fuel inventories | **93.3** | 100.7 |
| Materials and supplies, at average cost | **80.9** | 87.2 |
| Price risk management | **0.5** | 3.5 |
| Gas imbalances | **9.0** | 1.8 |
| Deferred income taxes | **187.7** | 32.1 |
| Fuel clause under recoveries | **—** | 1.8 |
| Assets held for sale | **25.5** | — |
| Other | **35.6** | 30.9 |
| Total current assets | **794.2** | 652.7 |
| OTHER PROPERTY AND INVESTMENTS, at cost | **52.2** | 46.7 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| In service | **11,504.4** | 10,315.9 |
| Construction work in progress | **387.5** | 499.0 |
| Total property, plant and equipment | **11,891.9** | 10,814.9 |
| Less accumulated depreciation | **3,547.1** | 3,340.9 |
| Net property, plant and equipment | **8,344.8** | 7,474.0 |
| DEFERRED CHARGES AND OTHER ASSETS | | |
| Regulatory assets | **510.6** | 507.9 |
| Intangible assets, net | **127.4** | 137.0 |
| Goodwill | **39.4** | 39.4 |
| Price risk management | **—** | 0.3 |
| Other | **53.6** | 48.0 |
| Total deferred charges and other assets | **731.0** | 732.6 |
| TOTAL ASSETS | **$ 9,922.2** | $ 8,906.0 |

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

**OGE ENERGY CORP.**
**CONSOLIDATED BALANCE SHEETS (Continued)**

| December 31 *(In millions)* | **2012** | 2011 |
|---|---|---|
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| CURRENT LIABILITIES | | |
| Short-term debt | **$ 430.9** | $ 277.1 |
| Accounts payable | **396.7** | 388.0 |
| Dividends payable | **41.2** | 38.5 |
| Customer deposits | **70.3** | 67.6 |
| Accrued taxes | **48.1** | 42.3 |
| Accrued interest | **55.0** | 54.8 |
| Accrued compensation | **55.2** | 47.8 |
| Price risk management | **0.3** | 0.4 |
| Gas imbalances | **5.0** | 9.8 |
| Fuel clause over recoveries | **109.2** | 7.7 |
| Other | **64.5** | 64.5 |
| Total current liabilities | **1,276.4** | 998.5 |
| LONG-TERM DEBT | **2,848.6** | 2,737.1 |
| DEFERRED CREDITS AND OTHER LIABILITIES | | |
| Accrued benefit obligations | **399.8** | 360.8 |
| Deferred income taxes | **1,948.8** | 1,651.4 |
| Deferred investment tax credits | **3.9** | 6.1 |
| Regulatory liabilities | **245.1** | 230.7 |
| Deferred revenues | **37.7** | 40.8 |
| Price risk management | **—** | 0.1 |
| Other | **89.5** | 61.2 |
| Total deferred credits and other liabilities | **2,724.8** | 2,351.1 |
| Total liabilities | **6,849.8** | 6,086.7 |
| COMMITMENTS AND CONTINGENCIES (NOTE 16) | | |
| STOCKHOLDERS' EQUITY | | |
| Common stockholders' equity | **1,047.4** | 1,035.3 |
| Retained earnings | **1,772.4** | 1,574.8 |
| Accumulated other comprehensive loss, net of tax | **(49.1)** | (40.6) |
| Treasury stock, at cost | **(3.5)** | (6.2) |
| Total OGE Energy stockholders' equity | **2,767.2** | 2,563.3 |
| Noncontrolling interests | **305.2** | 256.0 |
| Total stockholders' equity | **3,072.4** | 2,819.3 |
| TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY | **$ 9,922.2** | $ 8,906.0 |

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

## OGE ENERGY CORP.
## CONSOLIDATED STATEMENTS OF CAPITALIZATION

| December 31 *(In millions)* | | | 2012 | | 2011 |
|---|---|---|---|---|---|
| STOCKHOLDERS' EQUITY | | | | | |
| Common stock, par value $0.01 per share; authorized 225.0 shares; and outstanding 98.8 and 98.1 shares, respectively | | $ | **1.0** | $ | 1.0 |
| Premium on common stock | | | **1,046.4** | | 1,034.3 |
| Retained earnings | | | **1,772.4** | | 1,574.8 |
| Accumulated other comprehensive loss, net of tax | | | **(49.1)** | | (40.6) |
| Treasury stock, at cost, 0.1 and 0.1 shares, respectively | | | **(3.5)** | | (6.2) |
| Total OGE Energy stockholders' equity | | | **2,767.2** | | 2,563.3 |
| Noncontrolling interest | | | **305.2** | | 256.0 |
| Total stockholders' equity | | | **3,072.4** | | 2,819.3 |
| | | | | | |
| LONG-TERM DEBT | | | | | |
| SERIES | DUE DATE | | | | |
| Senior Notes - OGE Energy | | | | | |
| 5.00% | Senior Notes, Series Due November 15, 2014 | | **100.0** | | 100.0 |
| Unamortized discount | | | **(0.1)** | | (0.2) |
| Senior Notes - OG&E | | | | | |
| 5.15% | Senior Notes, Series Due January 15, 2016 | | **110.0** | | 110.0 |
| 6.50% | Senior Notes, Series Due July 15, 2017 | | **125.0** | | 125.0 |
| 6.35% | Senior Notes, Series Due September 1, 2018 | | **250.0** | | 250.0 |
| 8.25% | Senior Notes, Series Due January 15, 2019 | | **250.0** | | 250.0 |
| 6.65% | Senior Notes, Series Due July 15, 2027 | | **125.0** | | 125.0 |
| 6.50% | Senior Notes, Series Due April 15, 2028 | | **100.0** | | 100.0 |
| 6.50% | Senior Notes, Series Due August 1, 2034 | | **140.0** | | 140.0 |
| 5.75% | Senior Notes, Series Due January 15, 2036 | | **110.0** | | 110.0 |
| 6.45% | Senior Notes, Series Due February 1, 2038 | | **200.0** | | 200.0 |
| 5.85% | Senior Notes, Series Due June 1, 2040 | | **250.0** | | 250.0 |
| 5.25% | Senior Notes, Series Due May 15, 2041 | | **250.0** | | 250.0 |
| 3.70% | Tinker Debt, Due August 31, 2062 | | **10.7** | | — |
| Other Bonds - OG&E | | | | | |
| 0.22% - 0.40% | Garfield Industrial Authority, January 1, 2025 | | **47.0** | | 47.0 |
| 0.21% - 0.41% | Muskogee Industrial Authority, January 1, 2025 | | **32.4** | | 32.4 |
| 0.20% - 0.47% | Muskogee Industrial Authority, June 1, 2027 | | **56.0** | | 56.0 |
| Unamortized discount | | | **(5.8)** | | (6.2) |
| Enogex | | | | | |
| 6.875% | Senior Notes, Series Due July 15, 2014 | | **200.0** | | 200.0 |
| 1.72% | Enogex LLC Term Loan Agreement, Due August 2, 2015 | | **250.0** | | — |
| —% | Enogex LLC Revolving Credit Agreement, Due December 13, 2016 | | **—** | | 150.0 |
| 6.25% | Senior Notes, Series Due March 15, 2020 | | **250.0** | | 250.0 |
| Unamortized discount | | | **(1.6)** | | (1.9) |
| Total long-term debt | | | **2,848.6** | | 2,737.1 |
| Total Capitalization | | $ | **5,921.0** | $ | 5,556.4 |

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

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

| *(In millions)* | Common Stock | Premium on Common Stock | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interest | Treasury Stock | Total |
|---|---|---|---|---|---|---|---|
| Balance at December 31, 2009 | $ 1.0 | $ 886.7 | $ 1,227.8 | $ (74.7) | $ 20.0 | $ — | $ 2,060.8 |
| Comprehensive income (loss) | | | | | | | |
| Net income | — | — | 295.3 | — | 5.1 | — | 300.4 |
| Other comprehensive income (loss), net of tax | — | — | — | 14.5 | (5.8) | — | 8.7 |
| Comprehensive income (loss) | — | — | 295.3 | 14.5 | (0.7) | — | 309.1 |
| Dividends declared on common stock | — | — | (142.5) | — | — | — | (142.5) |
| Issuance of common stock | — | 17.0 | — | — | — | — | 17.0 |
| Stock-based compensation | — | 10.4 | — | — | — | — | 10.4 |
| Contributions from noncontrolling interest partners | — | 88.1 | — | — | 95.1 | — | 183.2 |
| Distributions to noncontrolling interest partners | — | — | — | — | (4.0) | — | (4.0) |
| Deferred income taxes attributable to contributions from noncontrolling interest partners | — | (34.0) | — | — | — | — | (34.0) |
| Balance at December 31, 2010 | $ 1.0 | $ 968.2 | $ 1,380.6 | $ (60.2) | $ 110.4 | $ — | $ 2,400.0 |
| Comprehensive income (loss) | | | | | | | |
| Net income | — | — | 342.9 | — | 20.7 | — | 363.6 |
| Other comprehensive income (loss), net of tax | — | — | — | 19.6 | 0.3 | — | 19.9 |
| Comprehensive income (loss) | — | — | 342.9 | 19.6 | 21.0 | — | 383.5 |
| Dividends declared on common stock | — | — | (148.7) | — | — | — | (148.7) |
| Issuance of common stock | — | 14.8 | — | — | — | — | 14.8 |
| Stock-based compensation | — | 5.8 | — | — | — | — | 5.8 |
| Contributions from noncontrolling interest partners | — | 74.4 | — | — | 142.0 | — | 216.4 |
| Distributions to noncontrolling interest partners | — | — | — | — | (17.4) | — | (17.4) |
| Deferred income taxes attributable to contributions from noncontrolling interest partners | — | (28.9) | — | — | — | — | (28.9) |
| Purchase of treasury stock | — | — | — | — | — | (6.2) | (6.2) |
| Balance at December 31, 2011 | $ 1.0 | $ 1,034.3 | $ 1,574.8 | $ (40.6) | $ 256.0 | $ (6.2) | $ 2,819.3 |
| Comprehensive income (loss) | | | | | | | |
| Net income | **—** | **—** | **355.0** | **—** | **30.0** | **—** | **385.0** |
| Other comprehensive income (loss), net of tax | **—** | **—** | **—** | **(8.5)** | **(3.5)** | **—** | **(12.0)** |
| Comprehensive income (loss) | **—** | **—** | **355.0** | **(8.5)** | **26.5** | **—** | **373.0** |
| Dividends declared on common stock | **—** | **—** | **(157.4)** | **—** | **—** | **—** | **(157.4)** |
| Issuance of common stock | **—** | **14.3** | **—** | **—** | **—** | **—** | **14.3** |
| Stock-based compensation and other | **—** | **(8.7)** | **—** | **—** | **(0.2)** | **6.1** | **(2.8)** |
| Contributions from noncontrolling interest partners | **—** | **10.7** | **—** | **—** | **35.5** | **—** | **46.2** |
| Distributions to noncontrolling interest partners | **—** | **—** | **—** | **—** | **(12.6)** | **—** | **(12.6)** |
| Deferred income taxes attributable to contributions from noncontrolling interest partners | **—** | **(4.2)** | **—** | **—** | **—** | **—** | **(4.2)** |
| Purchase of treasury stock | **—** | **—** | **—** | **—** | **—** | **(3.4)** | **(3.4)** |
| Balance at December 31, 2012 | **$ 1.0** | **$ 1,046.4** | **$ 1,772.4** | **$ (49.1)** | **$ 305.2** | **$ (3.5)** | **$ 3,072.4** |

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

## 1. Summary of Significant Accounting Policies

### Organization

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

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

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. This new organization is intended to facilitate the execution of Enogex's strategy through an enhanced focus on asset optimization and active management of its growing natural gas, NGLs and condensate positions. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. Enogex's operations are now organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. At December 31, 2012, OGE Energy indirectly owns a 79.9 percent membership interest in Enogex Holdings, which in turn owns all of the membership interests in Enogex LLC, a Delaware single-member limited liability company (see Note 4). The Company consolidates Enogex Holdings in its Consolidated Financial Statements as OGE Energy has a controlling financial interest over the operations of Enogex Holdings. Also, Enogex LLC holds a 50 percent ownership interest in Atoka. The Company consolidates Atoka in its Consolidated Financial Statements as Enogex acts as the managing member of Atoka and has control over the operations of Atoka.

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

### Basis of Presentation

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at December 31, 2012 and 2011 and the results of its operations and cash flows for the years ended December 31, 2012, 2011 and 2010, have been included and are of a normal recurring nature except as otherwise disclosed.

### Accounting Records

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

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

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

| December 31 *(In millions)* | | **2012** | | 2011 |
|---|---|---|---|---|
| Regulatory Assets | | | | |
| Current | | | | |
| Crossroads wind farm rider under recovery (A) | **$** | **14.9** | $ | 2.5 |
| Oklahoma demand program rider under recovery (A) | | **9.2** | | 8.1 |
| Fuel clause under recoveries | | **—** | | 1.8 |
| Other (A) | | **2.9** | | 3.6 |
| Total Current Regulatory Assets | **$** | **27.0** | $ | 16.0 |
| Non-Current | | | | |
| Benefit obligations regulatory asset | **$** | **370.6** | $ | 359.2 |
| Income taxes recoverable from customers, net | | **54.7** | | 54.0 |
| Smart Grid | | **42.8** | | 37.2 |
| Unamortized loss on reacquired debt | | **13.0** | | 14.2 |
| Deferred storm expenses | | **12.7** | | 23.8 |
| Deferred pension expenses | | **4.5** | | 9.1 |
| Other | | **12.3** | | 10.4 |
| Total Non-Current Regulatory Assets | **$** | **510.6** | $ | 507.9 |
| Regulatory Liabilities | | | | |
| Current | | | | |
| Fuel clause over recoveries | **$** | **109.2** | $ | 7.7 |
| Smart Grid rider over recovery (B) | | **24.1** | | 24.3 |
| Other (B) | | **7.8** | | 13.7 |
| Total Current Regulatory Liabilities | **$** | **141.1** | $ | 45.7 |
| Non-Current | | | | |
| Accrued removal obligations, net | **$** | **218.2** | $ | 208.2 |
| Deferred pension credits | | **17.7** | | — |
| Pension tracker | | **9.2** | | 22.5 |
| Total Non-Current Regulatory Liabilities | **$** | **245.1** | $ | 230.7 |

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

OG&E recovers a return on the capital expenditures along with operation and maintenance expense and depreciation expense related to the Crossroads wind farm through a rider established by the OCC. OG&E began recovery in the fourth quarter of 2011 and believes the rider will continue until new rates are implemented in OG&E's next general rate case.

OG&E recovers program costs related to the Demand and Energy Efficiency Program. An extension of the demand program rider was approved in December 2012, which allows for the recovery of demand program costs, lost revenues associated with any achieved energy, demand savings and performance based incentives and the recovery of costs associated with research and development investments through December 2015.

Fuel clause under recoveries are generated from under recoveries from OG&E's customers when OG&E's cost of fuel exceeds the amount billed to its customers. Fuel clause over recoveries are generated from over recoveries from OG&E's customers when the amount billed to its customers exceeds OG&E's cost of fuel. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances.

The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss, prior service cost and net transition obligation. These expenses were allowed to be recorded as a regulatory asset as OG&E had historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates and there was no negative evidence that the existing regulatory treatment would change. If, in the future, the regulatory bodies indicate a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the benefit obligations regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

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

| December 31 *(In millions)* | | **2012** | | 2011 |
|---|---|---|---|---|
| Pension Plan and Restoration of Retirement Income Plan: | | | | |
| Net loss | **$** | **278.6** | $ | 266.3 |
| Prior service cost | | **4.5** | | 7.0 |
| Postretirement plans: | | | | |
| Net loss | | **134.6** | | 144.2 |
| Prior service cost | | **(47.1)** | | (60.8) |
| Net transition obligation | | **—** | | 2.5 |
| Total | **$** | **370.6** | $ | 359.2 |

The following amounts in the benefit obligations regulatory asset at December 31, 2012 are expected to be recognized as components of net periodic benefit cost in 2013:

| *(In millions)* | | |
|---|---|---|
| Pension Plan and Restoration of Retirement Income Plan: | | |
| Net loss | **$** | **19.8** |
| Prior service cost | | **2.0** |
| Postretirement plans: | | |
| Net loss | | **18.1** |
| Prior service cost | | **(13.7)** |
| Total | **$** | **26.2** |

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

OG&E recovers the cost of system-wide deployment of smart grid technology and implementing the smart grid pilot program, the incremental costs for web portal access, education and providing home energy reports and stranded costs associated with OG&E's existing meters. The costs recoverable from Oklahoma customers for system-wide deployment of smart grid technology and implementing the smart grid pilot program were capped at $366.4 million (inclusive of the U.S. Department of Energy grant award amount) subject to an offset for any recovery of those costs from Arkansas customers and are currently being recovered through a rider which will remain in effect until the smart grid project costs are included in base rates in OG&E's next general rate case. This project was completed in late 2012 and the smart grid project costs did not exceed $366.4 million. The incremental costs for web portal access, education and home energy reports are capped at $6.9 million and will be recovered in base rates in OG&E's next general rate case. The stranded costs associated with OG&E's existing meters, which have been replaced by smart meters, were accumulated during the smart grid deployment and recovery of the stranded costs will be included in future rate cases. OG&E began recovering the estimated capital costs of $14 million and associated operation and maintenance costs for deployment of smart grid technology, along with incremental costs for web portal access and education of $0.8 million, through a rider beginning with the first billing cycle in January 2013 through December 2013.

OG&E defers the Oklahoma storm-related operation and maintenance expenses in excess of $2.7 million and reserves for any Oklahoma storm-related operation and maintenance expenses less than $2.7 million. OG&E will recover the deferred amounts over a five-year period ending in August 2017.

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.

OG&E recovers specific amounts of pension and postretirement medical costs in rates approved in its Oklahoma rate cases. In accordance with approved orders, OG&E defers the difference between actual pension and postretirement medical expenses and the amount approved in its last Oklahoma rate case as a regulatory asset or regulatory liability. These amounts have been recorded in Pension tracker regulatory liability in the regulatory assets and liabilities table above.

In July 2009, OG&E was allowed to recover previously deferred pension costs over a four-year period ending in August 2013. OG&E also recovers its 2006 and 2007 pension settlement costs in Arkansas, which are being amortized over a 10-year period ending in January 2020. Both the Oklahoma and Arkansas pension plan expenses are reflected in Deferred Pension expenses asset in the regulatory assets and liabilities table above.

In September 2011, OG&E was allowed to include postretirement medical expenses in its pension tracker. In August 2012, OG&E was allowed to recover pension and postretirement medical expenses over a two-year period ending July 2014 which is included in Deferred Pension credits liability in the regulatory assets and liabilities table above.

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

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

**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 for all Company segments includes the determination of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets), income taxes, contingency reserves, asset retirement obligations, fair value and cash flow hedges and the allowance for uncollectible accounts receivable. For the electric utility segment, the most significant judgment is also exercised in the valuation of regulatory assets and liabilities and unbilled revenues. For the natural gas transportation and storage segment and the natural gas gathering and processing segment, the most significant judgment is also exercised in the valuation of operating revenues, natural gas purchases, purchase and sale contracts, assets and depreciable lives of property, plant and equipment, amortization methodologies related to intangible assets and impairment assessments of goodwill.

**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. Also, a portion of the uncollectible provision related to fuel is being recovered through the fuel adjustment clause. 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 Enogex believes the collection of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was $2.6 million and $3.8 million at December 31, 2012 and 2011, respectively.

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

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

**Fuel Inventories**

***OG&E***

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. OG&E uses the weighted-average cost method of accounting for inventory that is physically added to or withdrawn from storage or stockpiles. The amount of fuel inventory was $76.8 million and $76.9 million at December 31, 2012 and 2011, respectively.

***Enogex***

Natural gas inventory is held by Enogex, through its transportation and storage business, to provide operational support for its pipeline deliveries and to manage its leased storage capacity. In an effort to mitigate market price exposures, Enogex may enter into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is valued using moving average cost and is recorded at the lower of cost or market. As part of its asset management activity, Enogex injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. During the years ended December 31, 2012, 2011 and 2010, Enogex recorded write-downs to market value related to natural gas storage inventory of $5.5 million, $4.8 million and $0.3 million, respectively. The amount of Enogex's natural gas inventory was $16.5 million and $23.7 million at December 31, 2012 and 2011, respectively. The cost of gas associated with sales of natural gas storage inventory is presented in Cost of Goods Sold on the Consolidated Statements of Income.

**Gas Imbalances**

***OG&E***

Gas imbalances occur when the actual amounts of natural gas delivered from or received by OG&E differ from the amounts scheduled to be delivered or received. OG&E values all imbalances at an average of current market indices applicable to OG&E's operations, not to exceed net realizable value.

***Enogex***

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

**Property, Plant and Equipment**

***OG&E***

All property, plant and equipment is recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and the allowance for funds used during construction. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and the cost of such property is charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance net of any salvage proceeds 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 table below presents OG&E's ownership interest in the jointly-owned McClain Plant and the jointly-owned Redbud Plant, and, as disclosed below, only OG&E's ownership interest is reflected in the property, plant and equipment and accumulated depreciation balances in these tables. The owners of the remaining interests in the McClain Plant and the Redbud Plant are responsible for providing their own financing of capital expenditures. Also, only OG&E's proportionate interests of any direct expenses of the McClain Plant and the Redbud Plant such as fuel, maintenance expense and other operating expenses are included in the applicable financial statement captions in the Consolidated Statement of Income.

| December 31, 2012 *(In millions)* | Percentage Ownership | Total Property, Plant and Equipment | Accumulated Depreciation | Net Property, Plant and Equipment |
|---|---|---|---|---|
| McClain Plant | **77%** | **$ 182.1** | **$ 56.3** | **$ 125.8** |
| Redbud Plant (A) | **51%** | **$ 458.5** | **$ 69.5** | **$ 389.0** |

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $23.3 million.

***Enogex***

All property, plant and equipment is recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and capitalized interest. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance net of any salvage proceeds 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 Cox City Plant Fire**

On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. The damaged train was replaced and the facility was returned to full service in September 2011. The total cost necessary to return the facility back to full service was $29.6 million. In the fourth quarter of 2011, Enogex received a partial insurance reimbursement of $7.4 million and recognized a gain of $3.0 million on insurance proceeds. In March 2012, Enogex reached a settlement agreement with its insurers in this matter. As a result of the settlement agreement, Enogex received additional reimbursements of $7.6 million and recognized a gain of $7.5 million on insurance proceeds in 2012.

In a period in which the Company has an event that results in the recognition of a material gain or loss on an event that is covered by insurance proceeds, the Company records an impairment loss for the book value of the damaged asset and an offsetting gain for insurance proceeds if recovery of the loss is considered probable. To the extent proceeds from an insurance settlement exceed recognized losses, the Company records a gain on insurance proceeds in earnings as the receipts of proceeds are determined to be probable.

***OGE Energy Consolidated***

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

| December 31, 2012 *(In millions)* | Total Property, Plant and Equipment | Accumulated Depreciation | Net Property, Plant and Equipment |
|---|---|---|---|
| *OGE Energy (holding company)* | | | |
| Property, plant and equipment | **$ 142.1** | **$ 103.2** | **$ 38.9** |
| OGE Energy property, plant and equipment | **142.1** | **103.2** | **38.9** |
| *OG&E* | | | |
| Distribution assets | **3,222.7** | **969.6** | **2,253.1** |
| Electric generation assets (A) | **3,446.6** | **1,242.4** | **2,204.2** |
| Transmission assets (B) | **1,712.6** | **359.8** | **1,352.8** |
| Intangible plant | **50.2** | **25.0** | **25.2** |
| Other property and equipment | **317.6** | **108.8** | **208.8** |
| OG&E property, plant and equipment | **8,749.7** | **2,705.6** | **6,044.1** |
| *Enogex* | | | |
| Natural gas transportation and storage assets | **988.6** | **292.7** | **695.9** |
| Natural gas gathering and processing assets | **2,011.5** | **445.6** | **1,565.9** |
| Enogex property, plant and equipment | **3,000.1** | **738.3** | **2,261.8** |
| Total property, plant and equipment | **$ 11,891.9** | **$ 3,547.1** | **$ 8,344.8** |

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $23.3 million.
(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.3 million.

| December 31, 2011 *(In millions)* | Total Property, Plant and Equipment | Accumulated Depreciation | Net Property, Plant and Equipment |
|---|---|---|---|
| *OGE Energy (holding company)* | | | |
| Property, plant and equipment | $ 124.6 | $ 90.6 | $ 34.0 |
| OGE Energy property, plant and equipment | 124.6 | 90.6 | 34.0 |
| *OG&E* | | | |
| Distribution assets | 2,981.3 | 920.3 | 2,061.0 |
| Electric generation assets (A) | 3,360.6 | 1,215.8 | 2,144.8 |
| Transmission assets (B) | 1,464.2 | 339.6 | 1,124.6 |
| Intangible plant | 43.2 | 20.3 | 22.9 |
| Other property and equipment | 293.9 | 96.3 | 197.6 |
| OG&E property, plant and equipment | 8,143.2 | 2,592.3 | 5,550.9 |
| *Enogex* | | | |
| Natural gas transportation and storage assets | 967.0 | 277.0 | 690.0 |
| Natural gas gathering and processing assets | 1,580.1 | 381.0 | 1,199.1 |
| Enogex property, plant and equipment | 2,547.1 | 658.0 | 1,889.1 |
| Total property, plant and equipment | $ 10,814.9 | $ 3,340.9 | $ 7,474.0 |

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $17.9 million.
(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.2 million.

The following table summarizes the Company's unamortized computer software costs.

| December 31 *(In millions)* | **2012** | 2011 |
|---|---|---|
| OGE Energy (holding company) | **$ 11.6** | $ 14.0 |
| OG&E | **17.6** | 6.7 |
| Enogex | **3.9** | 4.4 |
| Total | **$ 33.1** | $ 25.1 |

The following table summarized the Company's amortization expense for computer software costs.

| Year ended December 31 *(In millions)* | **2012** | 2011 | 2010 |
|---|---|---|---|
| OGE Energy (holding company) | **$ 6.8** | $ 6.4 | $ 5.3 |
| OG&E | **4.2** | 1.8 | 2.6 |
| Enogex | **3.1** | 1.0 | 2.2 |
| Total | **$ 14.1** | $ 9.2 | $ 10.1 |

**Intangible Assets**

***Enogex***

The following table below summarizes Enogex's intangible assets and related accumulated amortization at:

| *(In millions)* | Total Intangible Assets | Accumulated Amortization | Net Intangible Assets |
|---|---|---|---|
| December 31, 2012 | | | |
| Customer Contract / Acreage Dedication | **$ 141.9** | **$ 14.5** | **$ 127.4** |
| | | | |
| December 31, 2011 | | | |
| Customer Contract / Acreage Dedication | $ 141.9 | $ 4.9 | $ 137.0 |

In 2012, 2011 and 2010, amortization expense for intangible assets was $9.6 million, $2.1 million and $0.6 million, respectively, including amortization of certain customer-based intangible assets associated with the acquisition from Cordillera in November 2011, which is included in gross margin for financial reporting purposes.

The following table summarizes Enogex's expected amortization of intangible assets for each of the next five years.

| *(In millions)* | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|
| Expected amortization of intangible assets | $ 9.5 | $ 9.5 | $ 9.5 | $ 9.5 | $ 9.1 |

**Depreciation and Amortization**

***OG&E***

The provision for depreciation, which was 3.0 percent and 2.9 percent, respectively, of the average depreciable utility plant for 2012 and 2011, is provided on a straight-line method over the estimated service life of the utility assets. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant, and is based on the average life group method. Amortization of intangible assets is computed using the straight-line method. Of the remaining amortizable intangible plant balance at December 31, 2012, 92.4 percent will be amortized over 9.25 years with 7.6 percent of the remaining amortizable intangible plant balance at December 31, 2012 being amortized over their respective lives ranging from three to five years. Amortization of plant acquisition adjustments is provided on a straight-line basis over the estimated remaining service life of the acquired asset. Plant acquisition adjustments include $148.3 million for the Redbud Plant, which are being amortized over a 27-year life and $3.3 million for certain substation facilities in OG&E's service territory, which are being amortized over a 26 to 59-year period.

***Enogex***

For Enogex, depreciation is computed principally on the straight-line method using estimated useful lives of three to 83 years for transportation and storage assets, three to 30 years for gathering and processing assets and three to 15 years for general plant assets. Amortization of intangible assets other than debt costs is computed using the straight-line method over the respective lives of the intangible assets ranging up to 20 years.

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. Intangible assets are amortized on a straight-line basis over their useful lives using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

**Asset Retirement Obligations**

The Company has previously recorded asset retirement obligations that are being amortized over their respective lives ranging from three months to 74 years. The Company also has certain asset retirement obligations primarily related to Enogex's processing plants and compression sites that have not been recorded because the Company cannot determine when these obligations will be incurred.

The following table summarizes changes to the Company's asset retirement obligations during the years ended December 31, 2012 and 2011.

| *(In millions)* | **2012** | 2011 |
|---|---|---|
| Balance at January 1 | **$ 24.8** | $ 11.1 |
| Liabilities incurred (A) | **0.4** | 13.0 |
| Accretion expense | **1.9** | 0.7 |
| Revisions in estimated cash flows (B) | **26.9** | — |
| Balance at December 31 | **$ 54.0** | $ 24.8 |

(A) Due to certain Enogex compression assets in 2012 and OG&E's Crossroads wind farm in 2011.
(B) Due to changes to OG&E's asset retirement obligations related to its wind farms due to a change in the assumption related to the timing of removal used in the valuation of the asset retirement obligations.

**Assessing Impairment of Long-Lived Assets (Including Intangible Assets) and Goodwill**

The Company assesses its long-lived assets, including intangible assets with finite useful lives, for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset's carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets 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. 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. In 2011, the Company recorded a pre-tax impairment loss of $5.0 million, of which $2.5 million was the noncontrolling interest portion (see Note 5), related to the Atoka processing plant. The Company recorded no other material impairments in 2012, 2011 or 2010.

As a result of the gas gathering acquisitions in November 2011, Enogex recorded goodwill of $39.4 million. Enogex assesses its goodwill for impairment at least annually as of October 1 by comparing the fair value of the reporting unit with its book value, including goodwill. Enogex utilizes the income approach (generally accepted valuation approach) to estimate the fair value of the reporting unit, also giving consideration to alternative methods such as the market and cost approaches. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. Enogex performs its goodwill impairment testing at the natural gas gathering and processing segment reporting unit level. Enogex recorded no impairments of goodwill in 2012.

**Allowance for Funds Used During Construction**

For OG&E, allowance for funds used during construction is calculated according to the FERC pronouncements for the imputed cost of equity and borrowed funds. Allowance for funds used during construction, a non-cash item, is reflected as an increase to net other income and a reduction to interest expense in the Consolidated Statements of Income and as an increase to Construction Work in Progress in the Consolidated Balance Sheets. Allowance for funds used during construction rates, compounded semi-annually, were 8.93 percent, 8.71 percent and 8.89 percent for the years ended December 31, 2012, 2011 and 2010, respectively. The increase in the allowance for funds used during construction rates in 2012 was primarily due to an increase in commercial paper fees in 2012 which resulted in an increase in the cost of short-term debt borrowings.

**Collection of Sales Tax**

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

**Revenue Recognition**

***OG&E***

**General**

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

**SPP Purchases and Sales**

OG&E participates in the SPP energy imbalance service market in a dual role as a load serving entity and as a generation owner. The energy imbalance service market requires cash settlements for over or under schedules of generation and load. Market participants, including OG&E, are required to submit resource plans and can submit offer curves for each resource available for dispatch. A function of interchange accounting is to match participants' MWH entitlements (generation plus scheduled bilateral purchases) against their MWH obligations (load plus scheduled bilateral sales) during every hour of every day. If the net result during any given hour is an entitlement, the participant is credited with a spot-market sale to the SPP at the respective market price for that hour; if the net result is 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 NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated operating revenues are reflected in Accounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income. Enogex's key natural gas producer customers in 2012 included Chesapeake Energy Marketing Inc., Apache Corporation and Devon Energy Production Company, L.P. In 2012, these customers accounted for 19.6 percent, 17.8 percent and 10.6 percent, respectively, of Enogex's gathering and processing volumes. In 2012, Enogex's top 10 natural gas producer customers accounted for 73.0 percent of Enogex's gathering and processing volumes.

Enogex recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. Enogex depends on third-party facilities to transport and fractionate NGLs that it delivers to third parties at the inlet of their facilities. Additionally, one third party purchases 50 percent of the NGLs delivered to its system, which accounted for $297.3 million (43.3 percent), $285.4 million

(38.8 percent) and $279.8 million (46.0 percent), respectively, of Enogex's total NGLs sales for the years ended December 31, 2012, 2011 and 2010.

Enogex records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. In August 2010, Enogex completed construction of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Aid in Construction payments of $36.4 million received in excess of construction costs were recognized as Deferred Revenues on the Company's Consolidated Balance Sheet and are being amortized on a straight-line basis of $1.2 million per year over the life of the related firm transportation service agreement under which service commenced in June 2011. Also, in August 2011, Enogex and one of its five largest customers entered into new agreements, effective July 1, 2011, relating to the customer's natural gas gathering and processing volumes on the Oklahoma portion of Enogex's system. As a result, Enogex has recorded $7.1 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2012, which are expected to be recognized based on the estimated average fee per MMBtu processed by the end of 2014. Enogex has also recorded $1.5 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2012 in connection with other gathering and processing agreements.

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

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

Normal purchases and normal sales contracts are not recorded in PRM Assets or Liabilities in the Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by Enogex's operations and (ii) commodity contracts for the purchase and sale of NGLs produced by Enogex's gathering and processing business.

**Fuel Adjustment Clauses**

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component 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.

**Income Taxes**

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. 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 uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change. The Company recognizes interest related to unrecognized tax benefits in interest expense and recognizes penalties in other expense.

**Accrued Vacation**

The Company accrues vacation pay monthly by establishing a liability for vacation earned. Vacation may be taken as earned and is charged against the liability. At the end of each year, the liability represents the amount of vacation earned, but not taken.

**Accumulated Other Comprehensive Income (Loss)**

The following table summarizes the components of accumulated other comprehensive loss at December 31, 2012 and 2011 attributable to OGE Energy. At both December 31, 2012 and 2011, there was no accumulated other comprehensive loss related to Enogex's noncontrolling interest in Atoka.

| December 31 *(In millions)* | **2012** | 2011 |
|---|---|---|
| Pension Plan and Restoration of Retirement Income Plan: | | |
| Net loss | **$ (49.3)** | $ (42.1) |
| Prior service cost | **0.1** | (0.1) |
| Postretirement plans: | | |
| Net loss | **(15.7)** | (15.4) |
| Prior service cost | **7.2** | 9.0 |
| Net transition obligation | **—** | (0.1) |
| Deferred commodity contracts hedging gains | **0.1** | 3.3 |
| Deferred interest rate swap hedging losses | **(0.5)** | (0.7) |
| Total accumulated other comprehensive loss | **(58.1)** | (46.1) |
| Less: Accumulated other comprehensive loss attributable to noncontrolling interests | **(9.0)** | (5.5) |
| Accumulated other comprehensive loss, net of tax | **$ (49.1)** | $ (40.6) |

The amounts in accumulated other comprehensive loss at December 31, 2012 that are expected to be recognized into earnings in 2013 are as follows:

| *(In millions)* | |
|---|---|
| Pension Plan and Restoration of Retirement Income Plan: | |
| Net loss | $ 3.3 |
| Prior service cost | 0.1 |
| Postretirement plans: | |
| Net loss | 2.0 |
| Prior service cost | (1.8) |
| Deferred commodity contracts hedging gains | 0.1 |
| Deferred interest rate swap hedging losses | (0.2) |
| Total, net of tax | $ 3.5 |

**Environmental Costs**

Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense or deferred as a regulatory asset based on expected recovery from customers in future rates, if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where OG&E or Enogex have been designated as one of several potentially responsible parties, the amount accrued represents OG&E's or Enogex's estimated share of the cost. The Company had $5.8 million and $5.5 million in accrued environmental liabilities at December 31, 2012 and 2011, respectively, which are included in the summary of asset retirement obligations above.

**Reclassifications**

As discussed in Note 15, during the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented to conform to the 2012 presentation.

**2. Accounting Pronouncements**

In December 2011, the Financial Accounting Standards Board issued "Balance Sheet: Disclosures about Offsetting Assets and Liabilities." The new standard requires entities to disclose information about financial instruments and derivative instruments that are either offset on the balance sheet or are subject to a master netting arrangement, including providing both gross information and net information for recognized assets and liabilities, the net amounts presented on an entity's balance sheet and a description of the rights of setoff associated with these assets and liabilities. The new standard is applicable for all entities that have financial instruments and derivative instruments shown using a net presentation on an entity's balance sheet or are subject to a master netting arrangement. On January 31, 2013, the Financial Accounting Standards Board issued an update to this standard clarifying that the scope includes derivatives, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or are subject to a master netting arrangement or similar agreement. The new standard is effective for interim and annual reporting periods for fiscal years beginning on or after January 1, 2013 and is required to be applied retrospectively for all periods presented. The Company adopted this new standard effective January 1, 2013 and will provide any additional disclosures necessary to comply with the new standard in its Form 10-Q for the quarter ended March 31, 2013.

In February 2013, the Financial Accounting Standards Board issued "Comprehensive Income: Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income." The new standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, the new standard requires an entity to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items in net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. The new standard is applicable for all entities that issue financial statements that are presented in conformity with GAAP and that report items of other comprehensive income. The new standard is effective for interim and annual reporting periods for fiscal years beginning after December 15, 2012 and is required to be applied prospectively. The Company adopted this new standard effective January 1, 2013 and will provide any additional disclosures necessary to comply with the new standard in its Form 10-Q for the quarter ended March 31, 2013.

**3. Gas Gathering and Processing Acquisitions and Divestitures**

***Western Oklahoma Gathering Acquisition***

On September 23, 2011, Enogex entered into the following agreements: an agreement with Cordillera, Oxbow and West Canadian Midstream LLC pursuant to which Enogex agreed to acquire 100 percent of the membership interest in Roger Mills Gas Gathering, LLC, an Oklahoma limited liability company that owns an approximately 60-mile natural gas gathering system located in Roger Mills County and Ellis County, Oklahoma; an agreement with Cordillera and Oxbow pursuant to which Enogex agreed to acquire an approximately 30-mile natural gas gathering system located in Roger Mills County, Oklahoma; and agreements with Cordillera and other producers pursuant to which such producers agreed to provide Enogex with long-term acreage dedication in the area served by the gathering systems encompassing approximately 100,000 net acres. The gathering systems are located in the Granite Wash area. The aggregate purchase price for these transactions was $200.4 million which was paid in cash primarily from contributions from OGE Energy and the ArcLight group as well as cash generated from operations and bank borrowings. The transactions closed on November 1, 2011.

The acquisition described above was accounted for as a business combination. The following table summarizes the purchase price allocation for this acquisition.

| (In millions) | | |
|---|---|---|
| Current assets | $ | 5.4 |
| Net property, plant and equipment | | 24.3 |
| Intangible assets | | 136.3 |
| Goodwill | | 39.4 |
| Current liabilities assumed | | (5.0) |
| Total | $ | 200.4 |

The goodwill recognized from this acquisition primarily related to the benefits associated with combining the acquired assets with Enogex's existing assets and operations. All of the goodwill is deductible for tax purposes. The transactions have provided Enogex with key new opportunities in the Granite Wash area. The goodwill has been recorded in the natural gas gathering and processing segment. At December 31, 2012 and 2011, there were no changes in the recognized amount of goodwill resulting from this acquisition, as discussed in Note 1.

Intangible assets consist of identifiable customer contracts and relationships. The acquired intangible assets are being amortized on a straight-line basis over the estimated useful life of 15 years. The net amount of intangible assets and related accumulated amortization was $125.7 million and $10.6 million at December 31, 2012 and $134.8 million and $1.5 million at December 31, 2011, respectively.

***Granite Wash Gathering Acquisition***

On August 1, 2012, Enogex entered into agreements with Chesapeake Midstream Gas Services, L.L.C. and Mid-America Midstream Gas Services, L.L.C., wholly-owned subsidiaries of Access Midstream Partners, L.P. and Chesapeake Midstream Development, L.P., respectively, pursuant to which Enogex agreed to acquire approximately 235 miles of natural gas gathering pipelines, right-of-ways and certain other midstream assets that provide natural gas gathering services in the greater Granite Wash area. The transactions closed on August 31, 2012. The aggregate purchase price for these transactions was approximately $78.6 million including reimbursement for certain permitted capital expenditures incurred during the period beginning June 1, 2012 and ending August 31, 2012. Enogex utilized cash generated from operations and bank borrowings to fund the purchase. In addition, Enogex also incurred acquisition-related costs of $3.5 million for sales taxes on acquired assets, which are included in taxes other than income.

The acquisition described above was accounted for as a business combination. The purchase price is preliminary and has been allocated to property, plant and equipment based on the estimated fair values at the acquisition date using a third-party valuation expert. This allocation may change in subsequent financial statements. Enogex is currently evaluating the preliminary purchase price allocation, which will be adjusted as additional information relative to the fair value of assets becomes available. Enogex expects the purchase price allocations to be completed by the end of the first quarter of 2013.

In connection with these agreements, Enogex entered into a gas gathering and processing agreement with Chesapeake effective September 1, 2012 pursuant to which Enogex began providing fee-based natural gas gathering, compression, processing and transportation services to Chesapeake with respect to certain acreage dedicated by Chesapeake.

***Texas Panhandle Gathering Divestiture***

On January 2, 2013, Enogex and one of its five largest customers entered into new agreements, effective January 1, 2013, relating to the customer's gathering and processing volumes on the Texas portion of Enogex's system. The effects of this new arrangement are (i) a fixed fee processing agreement replaces the previous keep-whole agreement, (ii) the acreage dedicated by the customer to Enogex for gathering and processing in Texas has been increased for an extended term and (iii) the sale by Enogex of certain gas gathering assets in the Texas Panhandle portion of Enogex's system to this customer for cash proceeds of approximately $35 million. The sale of these assets was approved by the Company's and Enogex's Board of Directors in November 2012, therefore these assets were classified as held for sale on the Company's Consolidated Balance Sheet at December 31, 2012. Enogex expects to recognize a pre-tax gain of approximately $10 million in the first quarter of 2013 in its natural gas gathering and processing segment from the sale of these assets.

***Harrah Gathering and Processing Divestiture***

On April 1, 2011, Enogex completed the sale of its Harrah processing plant (38 MMcf/d of capacity) and the associated Wellston and Davenport gathering assets. The proceeds from the sale were $15.9 million and Enogex recorded a pre-tax gain in the second quarter of 2011 of $3.7 million in its natural gas gathering and processing segment.

**4. Noncontrolling Interests**

The following table summarizes changes in OGE Holdings' and the ArcLight group's membership interest in Enogex Holdings in 2012.

| *(In millions)* | OGE Holdings | ArcLight group | Total |
|---|---|---|---|
| Balance at December 31, 2011 (units) | 93.8 | 21.6 | 115.4 |
| *Ownership percentage at December 31, 2011* | 81.3% | 18.7% | 100.0% |
| | | | |
| Issuance of 5,294,118 units of Enogex Holdings (A) | 2.7 | 2.6 | 5.3 |
| Balance at December 31, 2012 (units) | 96.5 | 24.2 | 120.7 |
| *Ownership percentage at December 31, 2012* | 79.9% | 20.1% | 100.0% |

(A) Effective October 1, 2012, OGE Energy and the ArcLight group made contributions to Enogex Holdings of $45.0 million each to fund a portion of Enogex LLC's 2012 capital requirements.

The following table summarizes changes in OGE Energy's equity which represents changes in additional paid-in capital for unrecognized gains from the issuance of equity interests in Enogex Holdings to the ArcLight group in 2012.

| *(In millions)* | |
|---|---|
| Net income attributable to OGE Energy | $ 355.0 |
| Transfers from the noncontrolling interest | |
| Increase in paid-in capital for issuance of 5,294,118 units of Enogex Holdings (net of tax of $3.2 million) | 5.1 |
| Net transfers from the noncontrolling interest | 5.1 |
| Total of net income attributable to OGE Energy and transfers from noncontrolling interest | $ 360.1 |

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings makes quarterly distributions to its partners. The following table summarizes the quarterly distributions in 2012.

| *(In millions)* | OGE Holdings' Portion | ArcLight group's Portion | Total Distribution |
|---|---|---|---|
| First quarter 2012 | $ 24.4 | $ 5.6 | $ 30.0 |
| Second quarter 2012 | 10.1 | 2.4 | 12.5 |
| Third quarter 2012 | 10.2 | 2.3 | 12.5 |
| Fourth quarter 2012 | 10.2 | 2.3 | 12.5 |
| Total | $ 54.9 | $ 12.6 | $ 67.5 |

During 2012, Atoka's noncontrolling interest partner made contributions of $1.2 million to Atoka. Enogex LLC made no distributions during 2012 to its Atoka partner, as there is no minimum distribution requirement related to Atoka.

**5. Impairment of Assets**

Atoka previously operated a 20 MMcf/d refrigeration processing plant which processed gas gathered in the Atoka area. The processing plant was leased on a month-to-month basis. In August 2011, management made a decision to use third-party processing exclusively for gathered volumes dedicated to Atoka and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. As a result, in August 2011, Enogex recorded a pre-tax impairment loss of $5.0 million in the natural gas gathering and processing segment associated with the cost it had capitalized in connection with the installation of the leased plant as it will not be able to recover the remaining value of the assets through future cash flows. The noncontrolling interest portion of the pre-tax impairment loss was $2.5 million which was included in Net Income Attributable to Noncontrolling Interests in the Company's Consolidated Statement of Income.

## 6. Fair Value Measurements

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

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

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

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

The Company utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

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

### Contracts with Master Netting Arrangements

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

The following tables summarize the Company's assets and liabilities that are measured at fair value on a recurring basis at December 31, 2012 and 2011 as well as reconcile the Company's commodity contracts fair value to PRM Assets and Liabilities on the Company's Consolidated Balance Sheets at December 31, 2012 and 2011. There were no Level 3 investments held at December 31, 2012 or 2011.

| December 31, 2012 | | | | |
|---|---|---|---|---|
| *(In millions)* | Commodity Contracts | | Gas Imbalances (A) | |
| | Assets | Liabilities | Assets (B) | Liabilities (C) |
| Quoted market prices in active market for identical assets (Level 1) | **$ 5.0** | **$ 5.0** | **$ —** | **$ —** |
| Significant other observable inputs (Level 2) | **0.5** | **0.5** | **3.1** | **3.8** |
| Total fair value | **5.5** | **5.5** | **3.1** | **3.8** |
| Netting adjustments | **(5.0)** | **(5.2)** | **—** | **—** |
| Total | **$ 0.5** | **$ 0.3** | **$ 3.1** | **$ 3.8** |

| December 31, 2011 | | | | |
|---|---|---|---|---|
| *(In millions)* | Commodity Contracts | | Gas Imbalances (A) | |
| | Assets | Liabilities | Assets (B) | Liabilities (C) |
| Quoted market prices in active market for identical assets (Level 1) | $ 57.1 | $ 52.3 | $ — | $ — |
| Significant other observable inputs (Level 2) | 4.2 | 1.2 | 1.8 | 7.8 |
| Total fair value | 61.3 | 53.5 | 1.8 | 7.8 |
| Netting adjustments | (57.5) | (53.0) | — | — |
| Total | $ 3.8 | $ 0.5 | $ 1.8 | $ 7.8 |

(A) The Company uses the market approach to fair value its gas imbalance assets and liabilities, using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices.

(B) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $5.9 million at December 31, 2012 with no comparable item at December 31, 2011, 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.

(C) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $1.2 million and $2.0 million at December 31, 2012 and 2011, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

The following table summarizes the Company's assets that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during 2011. There were no Level 3 investments held at December 31, 2012 or 2011.

| | Commodity Contracts Assets |
|---|---|
| *(In millions)* | 2011 |
| Balance at January 1 | $ 13.3 |
| Total gains or losses included in other comprehensive income | (5.4) |
| Settlements | (7.9) |
| Balance at December 31 | $ — |

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

| | 2012 | | 2011 | |
|---|---|---|---|---|
| December 31 *(In millions)* | **Carrying Amount** | **Fair Value** | Carrying Amount | Fair Value |
| PRM Assets | | | | |
| Energy Derivative Contracts | **$ 0.5** | **$ 0.5** | $ 3.8 | $ 3.8 |
| PRM Liabilities | | | | |
| Energy Derivative Contracts | **$ 0.3** | **$ 0.3** | $ 0.5 | $ 0.5 |
| Long-Term Debt | | | | |
| OG&E Senior Notes | **$ 1,904.2** | **$ 2,401.6** | $ 1,903.8 | $ 2,383.8 |
| OG&E Industrial Authority Bonds | **135.4** | **135.4** | 135.4 | 135.4 |
| OG&E Tinker Debt (A) | **10.7** | **10.0** | — | — |
| OGE Energy Senior Notes | **99.9** | **106.3** | 99.8 | 108.5 |
| Enogex LLC Senior Notes | **448.4** | **493.4** | 448.1 | 497.9 |
| Enogex LLC Revolving Credit Agreement | **—** | **—** | 150.0 | 150.0 |
| Enogex LLC Term Loan | **250.0** | **250.0** | — | — |

(A) In September 2012, OG&E purchased the electric distribution system at Tinker Air Force Base for $10.7 million and began making installment payments over a 50-year term. The fair value of this debt was based on calculating the net present value of the monthly payments discounted by the Company's current borrowing rate. Since the debt was valued using unobservable inputs, it was classified as Level 3 in the fair value hierarchy. This was a non-cash investing and financing activity as discussed in Note 9.

The carrying value of the financial instruments included in the Consolidated Balance Sheets approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company's energy derivative contracts was determined generally based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties. The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

## 7. Derivative Instruments and Hedging Activities

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

**Commodity Price Risk**

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

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

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

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

**Interest Rate Risk**

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

**Credit Risk**

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

**Cash Flow Hedges**

For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income (Loss) and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. The Company measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. Forecasted transactions, which are designated as the hedged 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.

The Company designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing operations and natural gas transportation and storage operations (operational gas hedges). The Company also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. Enogex's cash flow hedges at December 31, 2012 mature by the end of the first quarter of 2013.

**Fair Value Hedges**

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

At December 31, 2012 and 2011, the Company had no derivative instruments that were designated as fair value hedges.

**Derivatives Not Designated As Hedging Instruments**

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

**Quantitative Disclosures Related to Derivative Instruments**

At December 31, 2012, the Company had the following derivative instruments that were designated as cash flow hedges.

| *(In millions)* | 2012 Gross Notional Volume (A) |
|---|---|
| Enogex hedges | |
| Natural gas sales | 3.7 |

(A) Natural gas in MMBtu's.

At December 31, 2012, the Company had the following derivative instruments that were not designated as hedging instruments.

| *(In millions)* | Gross Notional Volume (A) | |
|---|---|---|
| | Purchases | Sales |
| Natural gas (B) | | |
| Physical (C)(D) | 7.0 | 30.1 |
| Fixed Swaps/Futures | 16.2 | 17.9 |
| Basis Swaps | 7.3 | 6.7 |

(A) Natural gas in MMBtu's.
(B) 95.1 percent of the natural gas contracts have durations of one year or less, 2.9 percent have durations of more than one year and less than two years and 2.0 percent have durations of more than two years.
(C) Of the natural gas physical purchases and sales volumes not designated as hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.
(D) Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via Enogex's processing contracts, which are not derivative instruments and are excluded from the table above.

**Balance Sheet Presentation Related to Derivative Instruments**

The fair value of the derivative instruments that are presented in the Company's Consolidated Balance Sheet at December 31, 2012 are as follows:

| | | Fair Value | |
|---|---|---|---|
| Instrument | Balance Sheet Location | Assets | Liabilities |
| | | *(In millions)* | |
| Derivatives Designated as Hedging Instruments | | | |
| Natural Gas | | | |
| Financial Futures/Swaps | Other Current Assets | **$ —** | **$ 0.5** |
| Total | | **$ —** | **$ 0.5** |
| Derivatives Not Designated as Hedging Instruments | | | |
| Natural Gas | | | |
| Financial Futures/Swaps | Current PRM | **$ 0.1** | **$ —** |
| | Other Current Assets | **5.0** | **4.7** |
| Physical Purchases/Sales | Current PRM | **0.4** | **0.3** |
| Total | | **$ 5.5** | **$ 5.0** |
| Total Gross Derivatives (A) | | **$ 5.5** | **$ 5.5** |

(A) See Note 6 for a reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2012.

The fair value of the derivative instruments that are presented in the Company's Consolidated Balance Sheet at December 31, 2011 are as follows:

| | | Fair Value | | | |
|---|---|---|---|---|---|
| Instrument | Balance Sheet Location | Assets | | Liabilities | |
| | | (In millions) | | | |
| Derivatives Designated as Hedging Instruments | | | | | |
| Natural Gas | | | | | |
| Financial Futures/Swaps | Other Current Assets | $ | 5.2 | $ | 0.3 |
| Total | | $ | 5.2 | $ | 0.3 |
| | | | | | |
| Derivatives Not Designated as Hedging Instruments | | | | | |
| Natural Gas | | | | | |
| Financial Futures/Swaps | Current PRM | $ | 0.4 | $ | — |
| | Other Current Assets | | 49.9 | | 49.9 |
| Physical Purchases/Sales | Current PRM | | 3.1 | | 0.4 |
| | Non-Current PRM | | 0.3 | | 0.1 |
| Financial Options | Other Current Assets | | 2.4 | | 2.8 |
| Total | | $ | 56.1 | $ | 53.2 |
| Total Gross Derivatives (A) | | $ | 61.3 | $ | 53.5 |

(A) See Note 6 for a reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2011.

**Income Statement Presentation Related to Derivative Instruments**

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2012.

***Derivatives in Cash Flow Hedging Relationships***

| *(In millions)* | | Amount Recognized in Other Comprehensive Income (A) | | Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income | | Amount Recognized in Income |
|---|---|---|---|---|---|---|
| Natural Gas Financial Futures/Swaps | **$** | **0.5** | **$** | **5.2** | **$** | **—** |
| Interest Rate Swap | | **—** | | **(0.4)** | | **—** |
| Total | **$** | **0.5** | **$** | **4.8** | **$** | **—** |

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income (Loss) at December 31, 2012 that is expected to be reclassified into income within the next 12 months is a loss of $0.2 million.

***Derivatives Not Designated as Hedging Instruments***

| *(In millions)* | | Amount Recognized in Income |
|---|---|---|
| Natural Gas Physical Purchases/Sales | **$** | **(11.7)** |
| Natural Gas Financial Futures/Swaps | | **1.1** |
| Total | **$** | **(10.6)** |

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2011.

***Derivatives in Cash Flow Hedging Relationships***

| *(In millions)* | Amount Recognized in Other Comprehensive Income | Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income | Amount Recognized in Income |
|---|---|---|---|
| NGLs Financial Options | $ (8.4) | $ (9.8) | $ — |
| Natural Gas Financial Futures/Swaps | 2.9 | (30.4) | — |
| Interest Rate Swap | — | (0.4) | — |
| Total | $ (5.5) | $ (40.6) | $ — |

***Derivatives Not Designated as Hedging Instruments***

| *(In millions)* | Amount Recognized in Income |
|---|---|
| Natural Gas Physical Purchases/Sales | $ (10.0) |
| Natural Gas Financial Futures/Swaps | 0.4 |
| Total | $ (9.6) |

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2010.

***Derivatives in Cash Flow Hedging Relationships***

| *(In millions)* | Amount Recognized in Other Comprehensive Income | Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income | Amount Recognized in Income |
|---|---|---|---|
| NGLs Financial Options | $ (9.7) | $ 1.2 | $ — |
| NGLs Financial Futures/Swaps | 1.7 | (3.7) | — |
| Natural Gas Financial Futures/Swaps | (14.9) | (25.9) | 0.2 |
| Interest Rate Swap | — | (0.4) | — |
| Total | $ (22.9) | $ (28.8) | $ 0.2 |

***Derivatives Not Designated as Hedging Instruments***

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

For derivatives designated as cash flow hedges in the tables above, amounts reclassified from Accumulated Other Comprehensive Income (Loss) into income (effective portion) and amounts recognized in income (ineffective portion) for the years ended December 31, 2012, 2011 and 2010, if any, are reported in Operating Revenues. For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2012, 2011 and 2010, if any, are reported in Operating Revenues.

**Credit-Risk Related Contingent Features in Derivative Instruments**

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Company's senior unsecured debt rating to a below investment grade rating, at December 31, 2012, the Company would have been required to post $0.2 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2012. 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.

## 8. Stock-Based Compensation

In 2008, the Company adopted, and its shareowners approved, the 2008 Stock Incentive Plan. Under the 2008 Stock Incentive Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees of the Company and its subsidiaries. The Company has authorized the issuance of up to 2,750,000 shares under the 2008 Stock Incentive Plan.

The following table summarizes the Company's pre-tax compensation expense and related income tax benefit for the years ended December 31, 2012, 2011 and 2010 related to the Company's performance units and restricted stock.

| Year ended December 31 *(In millions)* | **2012** | 2011 | 2010 |
|---|---|---|---|
| Performance units | | | |
| Total shareholder return | **$ 8.0** | $ 8.2 | $ 6.8 |
| Earnings per share | **4.2** | 5.5 | 2.5 |
| Total performance units | **12.2** | 13.7 | 9.3 |
| Restricted stock | **0.6** | 1.0 | 0.9 |
| Total compensation expense | **$ 12.8** | $ 14.7 | $ 10.2 |
| Income tax benefit | **$ 4.9** | $ 5.7 | $ 3.9 |

The Company has issued new shares to satisfy stock option exercises, restricted stock grants and payouts of earned performance units. In 2012, 2011 and 2010, there were 424,555 shares, 311,623 shares and 255,389 shares, respectively, of new common stock issued pursuant to the Company's stock incentive plans related to exercised stock options, restricted stock grants (net of forfeitures) and payouts of earned performance units. In 2012, there were 5,911 shares of restricted stock returned to the Company to satisfy tax liabilities.

In November 2012, the Company purchased 60,000 shares of its common stock at an average cost of $55.41 per share on the open market. These shares will be used to satisfy Enogex's portion of the Company's obligation to deliver shares of common stock related to long-term incentive payouts of earned performance units in 2013. The Company expects to purchase shares in the future to satisfy a portion of its obligation under its incentive plan. The Company records treasury stock purchases at cost. Treasury stock is presented as a reduction of stockholders' equity in the Company's Consolidated Balance Sheet.

### *Performance Units*

Under the 2008 Stock Incentive Plan, the Company has issued performance units which represent the value of one share of the Company's common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the 2008 Stock Incentive Plan). Each performance unit is subject to forfeiture if the recipient terminates employment with the Company or a subsidiary prior to the end of the 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 award cycle, further adjusted based on the achievement of the performance goals during the award cycle.

The performance units granted based on total shareholder return are contingently awarded and will be payable in shares of the Company's common stock subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a three-year award cycle (i.e., three-year cliff vesting period) is dependent on the Company's total shareholder return ranking relative to a peer group of companies. The performance units granted based on earnings per share are contingently awarded and will be payable in shares of the Company's common stock based on the Company's earnings per share 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 these performance units are classified as equity in the Consolidated Balance Sheet. If there is no or only a partial payout for the performance units at the end of the award cycle, the unearned performance units are cancelled. Payout requires 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.

**Performance Units – Total Shareholder Return**

The fair value of the performance units based on total shareholder return was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units is a fixed amount determined at the grant date fair value and is recognized over the 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 award cycle. There are no post-vesting restrictions related to the Company's performance units based on total shareholder return. The number of performance units granted based on total shareholder return and the assumptions used to calculate the grant date fair value of the performance units based on total shareholder return are shown in the following table.

| | **2012** | 2011 | 2010 |
|---|---|---|---|
| Number of units granted | **169,339** | 213,721 | 214,750 |
| Fair value of units granted | **$ 51.82** | $ 46.09 | $ 39.43 |
| Expected dividend yield | **3.0%** | 3.2% | 3.9% |
| Expected price volatility | **22.0%** | 33.0% | 34.0% |
| Risk-free interest rate | **0.38%** | 1.40% | 1.42% |
| Expected life of units (in years) | **2.87** | 2.87 | 2.87 |

**Performance Units – Earnings Per Share**

The fair value of the performance units based on earnings per share 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 earnings per share 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 earnings per share. The number of performance units granted based on earnings per share and the grant date fair value are shown in the following table.

| | **2012** | 2011 | 2010 |
|---|---|---|---|
| Number of units granted | **40,797** | 71,238 | 71,585 |
| Fair value of units granted | **$ 47.63** | $ 41.61 | $ 32.44 |

In 2012, the performance unit grant for Enogex employees that was previously based on earnings per share was changed to a cash payment that entitles Enogex employees to receive from 0 percent to 200 percent of the performance units granted based on the growth in Enogex's EBITDA over a three-year award cycle (i.e., three-year cliff vesting period) compared to a growth target set by the Compensation Committee of the Company's Board of Directors.

***Restricted Stock***

Under the 2008 Stock Incentive Plan and beginning in 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.

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 number of shares of restricted stock granted and the grant date fair value are shown in the following table.

| | **2012** | 2011 | 2010 |
|---|---|---|---|
| Shares of restricted stock granted | **5,412** | 17,902 | 26,653 |
| Fair value of restricted stock granted | **$ 53.44** | $ 48.82 | $ 40.78 |

A summary of the activity for the Company's performance units and restricted stock at December 31, 2012 and changes in 2012 are shown in the following table.

| | Performance Units | | | | | |
|---|---|---|---|---|---|---|
| | Total Shareholder Return | | Earnings Per Share | | Restricted Stock | |
| *(dollars in millions)* | Number of Units | Aggregate Intrinsic Value | Number of Units | Aggregate Intrinsic Value | Number of Shares | Aggregate Intrinsic Value |
| Units/Shares Outstanding at 12/31/11 | 706,124 | | 235,376 | | 37,244 | |
| Granted (A) | 169,339 | | 40,797 | | 5,412 | |
| Converted (B) | (291,294) | $ 30.6 | (97,099) | $ 10.2 | N/A | |
| Vested | N/A | | N/A | | (15,847) | $ 0.9 |
| Forfeited | (49,605) | | (15,155) | | (2,256) | |
| Units/Shares Outstanding at 12/31/12 | 534,564 | $ 46.3 | 163,919 | $ 13.8 | 24,553 | $ 1.4 |
| Units/Shares Fully Vested at 12/31/12 | 188,633 | $ 21.2 | 62,880 | $ 7.1 | | |

(A) For performance units, this represents the target number of performance units granted. Actual number of performance units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.
(B) These amounts represent performance units that vested at December 31, 2011 which were settled in February 2012.

A summary of the activity for the Company's non-vested performance units and restricted stock at December 31, 2012 and changes in 2012 are shown in the following table.

| | Performance Units | | | | | |
|---|---|---|---|---|---|---|
| | Total Shareholder Return | | Earnings Per Share | | Restricted Stock | |
| | Number of Units | Weighted-Average Grant Date Fair Value | Number of Units | Weighted-Average Grant Date Fair Value | Number of Shares | Weighted-Average Grant Date Fair Value |
| Units/Shares Non-Vested at 12/31/11 | 414,830 | $ 42.75 | 138,277 | $ 37.01 | 37,244 | $ 44.24 |
| Granted | 169,339 (A) | $ 51.82 | 40,797 (A) | $ 47.63 | 5,412 | $ 53.44 |
| Vested | (188,633) | $ 39.43 | (62,880) | $ 32.44 | (15,847) | $ 42.78 |
| Forfeited | (49,605) | $ 44.24 | (15,155) | $ 38.02 | (2,256) | $ 44.22 |
| Units/Shares Non-Vested at 12/31/12 | 345,931 | $ 48.79 | 101,039 | $ 44.00 | 24,553 | $ 47.21 |
| Units/Shares Expected to Vest | 323,303 | | 94,557 | | 24,553 | |

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

***Fair Value of Vested Performance Units and Restricted Stock***

A summary of the Company's fair value for its vested performance units and restricted stock is shown in the following table.

| Year ended December 31 *(In millions)* | **2012** | 2011 | 2010 |
|---|---|---|---|
| Performance units | | | |
| Total shareholder return | **$ 7.4** | $ 7.4 | $ 5.4 |
| Earnings per share | **4.1** | 3.9 | 1.9 |
| Restricted stock | **0.7** | 1.0 | 0.6 |

***Unrecognized Compensation Cost***

A summary of the Company's unrecognized compensation cost for its non-vested performance units and restricted stock and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

| December 31, 2012 | Unrecognized Compensation Cost *(in millions)* | Weighted Average to be Recognized *(in years)* |
|---|---|---|
| Performance units | | |
| Total shareholder return | $ 7.7 | 1.64 |
| Earnings per share | 3.9 | 1.14 |
| Total performance units | 11.6 | |
| Restricted stock | 0.5 | 1.96 |
| Total | $ 12.1 | |

***Stock Options***

The Company last issued stock options in 2004 and as of December 31, 2006, all stock options were fully vested and expensed. All stock options have a contractual life of 10 years. A summary of the activity for the Company's stock options at December 31, 2012 and changes during 2012 are shown in the following table.

| *(dollars in millions)* | Number of Options | Weighted-Average Exercise Price | Aggregate Intrinsic Value | Weighted-Average Remaining Contractual Term |
|---|---|---|---|---|
| Options Outstanding at 12/31/11 | 55,800 | $ 23.19 | | |
| Exercised | (36,200) | $ 23.41 | $ 2.0 | |
| Options Outstanding at 12/31/12 | 19,600 | $ 22.80 | $ 0.6 | 0.95 years |
| Options Fully Vested and Exercisable at 12/31/12 | 19,600 | $ 22.80 | $ 0.6 | 0.95 years |

A summary of the activity for the Company's exercised stock options in 2012, 2011 and 2010 are shown in the following table.

| Year ended December 31 *(In millions)* | **2012** | 2011 | 2010 |
|---|---|---|---|
| Intrinsic value (A) | **$ 2.0** | $ 2.2 | $ 2.5 |
| Cash received from stock options exercised | **0.8** | 1.3 | 3.2 |
| Income tax benefit realized for the tax deductions from exercised stock options (B) | **—** | — | 1.0 |

(A) The difference between the market value on the date of exercise and the option exercise price.

(B) The Company did not realize an income tax benefit for the tax deductions from the exercised stock options in 2012 and 2011 due to the Company being in a tax net operating loss position in 2012 and 2011.

## 9. Supplemental Cash Flow Information

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

| Year ended December 31 *(In millions)* | **2012** | 2011 | 2010 |
|---|---|---|---|
| **NON-CASH INVESTING AND FINANCING ACTIVITIES** | | | |
| Installment payments for Tinker electric distribution system | **$ 10.6** | $ — | $ — |
| Power plant long-term service agreement | **—** | 1.7 | 2.7 |
| Future installment payments to wind farm developer | **—** | — | 2.3 |
| | | | |
| **SUPPLEMENTAL CASH FLOW INFORMATION** | | | |
| Cash Paid During the Period for | | | |
| Interest (net of interest capitalized) (A) | **$ 161.3** | $ 138.9 | $ 144.6 |
| Income taxes (net of income tax refunds) | **(9.1)** | 4.7 | (139.5) |

(A) Net of interest capitalized of $8.0 million, $19.1 million and $8.0 million in 2012, 2011 and 2010, respectively.

## 10. Income Taxes

The items comprising income tax expense are as follows:

| Year ended December 31 *(In millions)* | **2012** | 2011 | 2010 |
|---|---|---|---|
| Provision (Benefit) for Current Income Taxes | | | |
| Federal | **$ (9.1)** | $ (5.4) | $ 12.8 |
| State | **0.5** | 0.1 | 1.8 |
| Total Provision (Benefit) for Current Income Taxes | **(8.6)** | (5.3) | 14.6 |
| Provision for Deferred Income Taxes, net | | | |
| Federal | **147.3** | 165.5 | 139.8 |
| State | **(1.5)** | 3.8 | 10.3 |
| Total Provision for Deferred Income Taxes, net | **145.8** | 169.3 | 150.1 |
| Deferred Federal Investment Tax Credits, net | **(2.1)** | (3.3) | (3.7) |
| Total Income Tax Expense | **$ 135.1** | $ 160.7 | $ 161.0 |

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal tax examinations by tax authorities for years prior to 2009 or state and local tax examinations by tax authorities for years prior to 2005. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. OG&E earns both Federal and Oklahoma state tax credits associated with production from its wind farms. In addition, OG&E and Enogex earn Oklahoma state tax credits associated with their investments in electric generating and natural gas processing facilities which further reduce the Company's effective tax rate. The following schedule reconciles the statutory Federal tax rate to the effective income tax rate:

| Year ended December 31 | **2012** | 2011 | 2010 |
|---|---|---|---|
| Statutory Federal tax rate | **35.0 %** | 35.0 % | 35.0 % |
| Amortization of net unfunded deferred taxes | **0.8** | 0.7 | 0.7 |
| Medicare Part D subsidy | **—** | 0.2 | 2.6 |
| Qualified production activities | **—** | — | (0.2) |
| State income taxes, net of Federal income tax benefit | **(0.1)** | 0.6 | 1.7 |
| Federal investment tax credits, net | **(0.4)** | (0.7) | (0.8) |
| 401(k) dividends | **(0.5)** | (0.5) | (0.6) |
| Income attributable to noncontrolling interest | **(1.6)** | (1.3) | (0.4) |
| Federal renewable energy credit (A) | **(7.2)** | (3.4) | (3.4) |
| Other | **—** | 0.1 | 0.3 |
| Effective income tax rate | **26.0 %** | 30.7 % | 34.9 % |

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

At December 31, 2012 and 2011, the Company had no material unrecognized tax benefits related to uncertain tax positions.

The deferred tax provisions are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by OG&E. The components of Deferred Income Taxes at December 31, 2012 and 2011, respectively, were as follows:

| December 31 *(In millions)* | **2012** | 2011 |
|---|---|---|
| Current Deferred Income Tax Assets | | |
| Net operating losses | **$ 152.4** | $ 15.8 |
| Accrued liabilities | **27.1** | 13.2 |
| Federal tax credits | **6.0** | — |
| Accrued vacation | **3.8** | 4.2 |
| Uncollectible accounts | **1.0** | 1.4 |
| Total Current Deferred Income Tax Assets | **190.3** | 34.6 |
| Current Accrued Income Tax Liabilities | | |
| Derivative instruments | **(2.6)** | (2.5) |
| Total Current Accrued Income Tax Liabilities | **(2.6)** | (2.5) |
| Current Deferred Income Tax Assets, net | **$ 187.7** | $ 32.1 |
| | | |
| Non-Current Deferred Income Tax Liabilities | | |
| Accelerated depreciation and other property related differences | **$ 1,660.3** | $ 1,437.5 |
| Investment in Enogex Holdings | **638.0** | 571.8 |
| Company pension plan | **52.4** | 67.5 |
| Income taxes refundable to customers, net | **21.2** | 28.0 |
| Regulatory asset | **18.8** | 21.2 |
| Bond redemption-unamortized costs | **4.0** | 4.4 |
| Derivative instruments | **1.5** | — |
| Total Non-Current Deferred Income Tax Liabilities | **2,396.2** | 2,130.4 |
| Non-Current Deferred Income Tax Assets | | |
| Net operating losses | **(159.1)** | (225.2) |
| State tax credits | **(83.7)** | (63.0) |
| Regulatory liabilities | **(71.4)** | (65.3) |
| Federal tax credits | **(69.6)** | (49.7) |
| Postretirement medical and life insurance benefits | **(57.6)** | (50.2) |
| Derivative instruments | **—** | (12.1) |
| Deferred Federal investment tax credits | **(1.5)** | (2.3) |
| Other | **(4.5)** | (11.2) |
| Total Non-Current Deferred Income Tax Assets | **(447.4)** | (479.0) |
| Non-Current Deferred Income Tax Liabilities, net | **$ 1,948.8** | $ 1,651.4 |

During 2012 and 2011, the Company had a Federal tax operating loss primarily caused by the accelerated tax "bonus" depreciation provision contained within the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 which allowed the Company to record a current income tax deduction for 100 percent of the cost of certain property placed into service in 2011 and 50 percent for certain property placed into service in 2012. For financial accounting purposes, the Company recorded an increase in its Non-Current Deferred Income Taxes Liability at December 31, 2012 and 2011 on the Company's Consolidated Balance Sheet to recognize the financial statement impact of this new law.

On January 2, 2013, the American Taxpayer Relief Act of 2012 was signed into law. Among other things, the law included an extension of bonus depreciation for one year for property generally placed in service before January 1, 2014. Because this new law was enacted in 2013, GAAP requires the law to be considered retroactive legislation, the impact of which must be recorded in the period enacted. The impact of the new law will be reflected in the Company's 2013 Consolidated Financial Statements as an increase in Deferred Tax Liabilities with a corresponding increase in Deferred Tax Assets related to the net operating loss.

In June 2010, new legislation was passed in Oklahoma that created a moratorium, from July 1, 2010 through June 30, 2012, on 30 income tax credits. For income tax purposes, credits affected by the moratorium could not be claimed for any event, transaction, investment, expenditure or other act for which the credits would otherwise be allowable. During this two-year period, affected credits generated by the Company were deferred and will be utilized at a future date. For financial accounting purposes, the Company is receiving the benefits as most of these credits did not expire if they were not utilized in the period they were generated.

***Other***

The Company sustained Federal and state tax operating losses in 2012 and 2011 caused primarily by bonus depreciation and other book verses tax temporary differences. As a result, the Company accrued Federal and state income tax benefits in 2012 and 2011. The Company can no longer carry these losses back to prior periods, therefore, these losses are being carried forward. In addition to the operating losses, the Company was unable to utilize the various tax credits that were generating during these years. These tax losses and credits are being carried as deferred tax assets and will be utilized in future periods. Under current law, the Company anticipates future taxable income will be sufficient to utilize all of the losses and credits before they begin to expire, accordingly no valuation allowance is considered necessary. The following table summarizes these carry forwards:

| *(In millions)* | Carry Forward Amount | Deferred Tax Asset | Earliest Expiration Date |
|---|---|---|---|
| Net operating losses | | | |
| State operating loss | $ 1,026.8 | $ 37.8 | 2030 |
| Federal operating loss | 781.9 | 273.7 | 2030 |
| Federal tax credits | 75.6 | 75.6 | 2029 |
| State tax credits | | | |
| Oklahoma investment tax credits | 100.5 | 65.3 | N/A |
| Oklahoma capital investment board credits | 7.3 | 7.3 | N/A |
| Oklahoma zero emission tax credits | 16.2 | 11.1 | 2020 |

Under tax law in effect at December 31, 2012, the Company projected utilization of $711.0 million of tax loss carry forward in 2013 and recorded a current deferred tax asset of $152.4 million. The remaining 159.1 million was recorded as a non-current deferred tax asset for utilization in periods after 2013. With the passage of the American Taxpayer Relief Act of 2012 on January 2, 2013, the Company now expects much lower utilization will result in 2013. The impact of the new law will be reflected in the Company's 2013 Consolidated Financial Statements as a decrease in Current Deferred Tax Assets with a corresponding increase in Deferred Tax Liabilities related to the net operating loss.

In January 2013, OG&E learned that a portion of certain Oklahoma investment tax credits previously recognized but not yet utilized may not be available for utilization in future years. If management determines that it is more likely than not that it will be unable to utilize these credits, OG&E will be required to record a reserve of $7.8 million ($5.1 million after tax) at such time.

## 11. Common Equity

***Automatic Dividend Reinvestment and Stock Purchase Plan***

The Company issued 246,549 shares of common stock under its Automatic Dividend Reinvestment and Stock Purchase Plan in 2012 and received proceeds of $13.4 million. The Company may, from time to time, issue additional shares under its Automatic Dividend Reinvestment and Stock Purchase Plan to fund capital requirements or working capital needs. At December 31, 2012, there were 2,122,494 shares of unissued common stock reserved for issuance under the Company's Automatic Dividend Reinvestment and Stock Purchase Plan.

### *Earnings Per Share*

Basic earnings per share is calculated by dividing net income attributable to OGE Energy by the weighted average number of the Company's common shares outstanding during the period. In the calculation of diluted earnings per share, weighted average shares outstanding are increased for additional shares that would be outstanding if potentially dilutive securities were converted to common stock. Potentially dilutive securities for the Company consist of performance units. Basic and diluted earnings per share for the Company were calculated as follows:

| *(In millions)* | **2012** | 2011 | 2010 |
|---|---|---|---|
| Net Income Attributable to OGE Energy | **$ 355.0** | $ 342.9 | $ 295.3 |
| Average Common Shares Outstanding | | | |
| Basic average common shares outstanding | **98.6** | 97.9 | 97.3 |
| Effect of dilutive securities: | | | |
| Contingently issuable shares (performance units) | **0.5** | 1.3 | 1.6 |
| Diluted average common shares outstanding | **99.1** | 99.2 | 98.9 |
| Basic Earnings Per Average Common Share Attributable to OGE Energy Common Shareholders | **$ 3.60** | $ 3.50 | $ 3.03 |
| Diluted Earnings Per Average Common Share Attributable to OGE Energy Common Shareholders | **$ 3.58** | $ 3.45 | $ 2.99 |
| Anti-dilutive shares excluded from earnings per share calculation | **—** | — | — |

## 12. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2012, the Company was in compliance with all of its debt agreements.

### *OG&E Industrial Authority Bonds*

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

| SERIES | DATE DUE | AMOUNT |
|---|---|---|
| | | *(In millions)* |
| 0.22% - 0.40% | Garfield Industrial Authority, January 1, 2025 | $ 47.0 |
| 0.21% - 0.41% | Muskogee Industrial Authority, January 1, 2025 | 32.4 |
| 0.20% - 0.47% | Muskogee Industrial Authority, June 1, 2027 | 56.0 |
| Total (redeemable during next 12 months) | | $ 135.4 |

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

### *Enogex Term Loan Agreement*

On August 2, 2012, Enogex entered into a $250 million, three-year term loan agreement with a maturity date of August 2, 2015. The loan was used to fund capital expenditures and for working capital purposes.

***Long-Term Debt Maturities***

Maturities of the Company's long-term debt during the next five years consist of $0.2 million, $300.2 million, $250.2 million, $110.2 million and $125.2 million in years 2013, 2014, 2015, 2016 and 2017, respectively.

The Company has previously incurred costs related to debt refinancings. Unamortized loss on reacquired debt is classified as a Non-Current Regulatory Asset, unamortized debt expense is 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.

## 13. Short-Term Debt and Credit Facilities

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $430.9 million and $277.1 million at December 31, 2012 and 2011, respectively, at a weighted-average interest rate of 0.43 percent and 0.48 percent, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at December 31, 2012.

Revolving Credit Agreements and Available Cash

| Entity | Aggregate Commitment | Amount Outstanding (A) | Weighted-Average Interest Rate | Maturity |
|---|---|---|---|---|
| | *(In millions)* | | | |
| OGE Energy (B) | $ 750.0 | $ 430.9 | 0.43% (E) | December 13, 2016 |
| OG&E (C) | 400.0 | 2.2 | 0.53% (E) | December 13, 2016 |
| Enogex LLC (D) | 400.0 | — | —% (E) | December 13, 2016 |
| | 1,550.0 | 433.1 | 0.43% | |
| Cash | 1.8 | N/A | N/A | N/A |
| Total | $ 1,551.8 | $ 433.1 | 0.43% | |

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 31, 2012.
(B) This bank facility is available to back up OGE Energy's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At December 31, 2012, there was $430.9 million in outstanding commercial paper borrowings.
(C) This bank facility is available to back up OG&E's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At December 31, 2012, there was $2.2 million supporting letters of credit.
(D) This bank facility is available to provide revolving credit borrowings for Enogex LLC. As Enogex LLC's credit agreement matures on December 13, 2016, along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Consolidated Balance Sheets.
(E) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit.

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

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, 2013 and ending December 31, 2014.

## 14. Retirement Plans and Postretirement Benefit Plans

***Pension Plan and Restoration of Retirement Income Plan***

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

Employees hired or rehired on or after December 1, 2009 do not participate in the Pension Plan but are eligible to participate in the 401(k) Plan where, for each pay period, the Company contributes to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

It is the Company's policy to fund the Pension Plan on a current basis based on the net periodic pension expense as determined by the Company's actuarial consultants. During 2012 and 2011, OGE Energy made contributions to its Pension Plan of $35 million and $50 million, respectively, to help ensure that the Pension Plan maintains an adequate funded status. Such contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. During 2013, OGE Energy expects to contribute up to $35 million to its Pension Plan. The expected contribution to the Pension Plan during 2013 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. OGE Energy could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

The Company provides a Restoration of Retirement Income Plan to those participants in the Company's Pension Plan whose benefits are subject to certain limitations of the Code. Participants in the Restoration of Retirement Income Plan receive the same benefits that they would have received under the Company's Pension Plan in the absence of limitations imposed by the Federal tax laws. The Restoration of Retirement Income Plan is intended to be an unfunded plan.

The following table presents the status of the Company's Pension Plan and Restoration of Retirement Income Plan at December 31, 2012 and 2011. 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 those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

| | Pension Plan | | Restoration of Retirement Income Plan | |
|---|---|---|---|---|
| December 31 *(In millions)* | **2012** | 2011 | **2012** | 2011 |
| Benefit obligations | **$ (747.1)** | $ (697.7) | **$ (14.5)** | $ (13.3) |
| Fair value of plan assets | **626.0** | 589.8 | **—** | — |
| Funded status at end of year | **$ (121.1)** | $ (107.9) | **$ (14.5)** | $ (13.3) |

The following table summarizes the benefit payments the Company expects to pay related to its Pension Plan and Restoration of Retirement Income Plan. These expected benefits are based on the same assumptions used to measure the Company's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

| *(In millions)* | Projected Benefit Payments |
|---|---|
| 2013 | $ 75.1 |
| 2014 | 94.5 |
| 2015 | 84.7 |
| 2016 | 77.2 |
| 2017 | 71.5 |
| After 2017 | 295.3 |

**Plan Investments, Policies and Strategies**

The Pension Plan assets are held in a trust which follows an investment policy and strategy designed to reduce the funded status volatility of the Plan by utilizing liability driven investing. The purpose of liability driven investing is to structure the asset portfolio to more closely resemble the pension liability and thereby more effectively hedge against changes in the liability. The investment policy follows a glide path approach that shifts a higher portfolio weighting to fixed income as the Plan's funded status increases. The table below sets forth the targeted fixed income and equity allocations at different funded status levels.

| Projected Benefit Obligation Funded Status Thresholds | <90% | 95% | 100% | 105% | 110% | 115% | 120% |
|---|---|---|---|---|---|---|---|
| Fixed income | 50% | 58% | 65% | 73% | 80% | 85% | 90% |
| Equity | 50% | 42% | 35% | 27% | 20% | 15% | 10% |
| Total | 100% | 100% | 100% | 100% | 100% | 100% | 100% |

Within the portfolio's overall allocation to equities, the funds are allocated according to the guidelines in the table below.

| Asset Class | Target Allocation | Minimum | Maximum |
|---|---|---|---|
| Domestic All-Cap/Large Cap Equity | 50% | 50% | 60% |
| Domestic Mid-Cap Equity | 15% | 5% | 25% |
| Domestic Small-Cap Equity | 15% | 5% | 25% |
| International Equity | 20% | 10% | 30% |

The Company has retained an investment consultant responsible for the general investment oversight, analysis, monitoring investment guideline compliance and providing quarterly reports to certain of the Company's members and the Company's Investment Committee. The various investment managers used by the trust operate within the general operating objectives as established in the investment policy and within the specific guidelines established for each investment manager's respective portfolio.

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 percent 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) |
|---|---|
| Core Fixed Income | Barclays Capital Aggregate Index |
| Interest Rate Sensitive Fixed Income | Barclays Capital Aggregate Index |
| Long Duration Fixed Income | Barclays Long Government/Credit |
| Equity Index | Standard & Poor's 500 Index |
| All-Cap Equity | Russell 3000 Index |
| | Russell 3000 Value Index |
| Mid-Cap Equity | Russell Midcap Index |
| | Russell Midcap Value Index |
| Small-Cap Equity | Russell 2000 Index |
| | Russell 2000 Value Index |
| International Equity | Morgan Stanley Capital Investment ACWI ex-US |

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 Services, Standard & Poor's Ratings Services or Fitch Ratings. The portfolio may invest up to 10 percent of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. The purchase of any of the Company's equity, debt or other securities is prohibited.

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The domestic mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell Midcap Index, small dividend yield, return on equity at or near the Russell Midcap Index and an earnings per share growth rate at or near the Russell Midcap Index. The domestic small-cap equity manager will purchase shares of companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and an 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 All Country World ex-US Index is the benchmark for comparative performance purposes. The Morgan Stanley Capital International All Country World ex-US Index is a market value weighted index designed to measure the combined equity market performance of developed and emerging markets countries, excluding the United States. All of the equities which are purchased for the international portfolio are thoroughly researched. Only companies with a market capitalization in excess of $100 million are allowable. No more than five percent of the portfolio can be invested in any one stock at the time of purchase. All securities are freely traded on a recognized stock exchange and there are no 144-A securities and no over-the-counter derivatives. The following investment categories are excluded: options (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares).

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

**Plan Investments**

The following tables summarize the Pension Plan's investments that are measured at fair value on a recurring basis at December 31, 2012 and 2011. There were no Level 3 investments held by the Pension Plan at December 31, 2012 and 2011.

| *(In millions)* | December 31, 2012 | Level 1 | Level 2 |
|---|---|---|---|
| Common stocks | | | |
| U.S. common stocks | $ **232.2** | $ **232.2** | $ **—** |
| Foreign common stocks | **39.9** | **39.9** | **—** |
| U.S. Government obligations | | | |
| U.S. treasury notes and bonds (A) | **138.6** | **138.6** | **—** |
| Mortgage-backed securities | **55.8** | **—** | **55.8** |
| Bonds, debentures and notes (B) | | | |
| Corporate fixed income and other securities | **98.4** | **—** | **98.4** |
| Mortgage-backed securities | **13.5** | **—** | **13.5** |
| Commingled fund (C) | **34.9** | **—** | **34.9** |
| Common/collective trust (D) | **25.6** | **—** | **25.6** |
| Foreign government bonds | **3.9** | **—** | **3.9** |
| U.S. municipal bonds | **0.8** | **—** | **0.8** |
| Interest-bearing cash | **0.2** | **0.2** | **—** |
| Forward contracts | | | |
| Receivable (foreign currency) | **0.4** | **—** | **0.4** |
| Payable (foreign currency) | **(0.4)** | **—** | **(0.4)** |
| Total Plan investments | $ **643.8** | $ **410.9** | $ **232.9** |
| Receivable from broker for securities sold | **0.8** | | |
| Interest and dividends receivable | **2.8** | | |
| Payable to broker for securities purchased | **(21.4)** | | |
| Total Plan assets | $ **626.0** | | |

| (In millions) | | December 31, 2011 | | Level 1 | | Level 2 |
|---|---|---|---|---|---|---|
| Common stocks | | | | | | |
| U.S. common stocks | $ | 179.7 | $ | 179.7 | $ | — |
| Foreign common stocks | | 59.5 | | 59.5 | | — |
| U.S. Government obligations | | | | | | |
| U.S. treasury notes and bonds (A) | | 118.8 | | 118.8 | | — |
| Mortgage-backed securities | | 72.0 | | — | | 72.0 |
| Other securities | | 1.0 | | — | | 1.0 |
| Bonds, debentures and notes (B) | | | | | | |
| Corporate fixed income and other securities | | 95.3 | | — | | 95.3 |
| Mortgage-backed securities | | 17.2 | | — | | 17.2 |
| Commingled fund (E) | | 38.5 | | — | | 38.5 |
| Common/collective trust (D) | | 29.6 | | — | | 29.6 |
| Foreign government bonds | | 2.9 | | — | | 2.9 |
| Interest-bearing cash | | 2.1 | | 2.1 | | — |
| U.S. municipal bonds | | 1.7 | | — | | 1.7 |
| Preferred stocks (foreign) | | 0.6 | | 0.6 | | — |
| Forward contracts | | | | | | |
| Receivable (foreign currency) | | 4.1 | | — | | 4.1 |
| Payable (foreign currency) | | (4.1) | | — | | (4.1) |
| Total Plan investments | $ | 618.9 | $ | 360.7 | $ | 258.2 |
| Receivable from broker for securities sold | | 4.8 | | | | |
| Interest and dividends receivable | | 3.1 | | | | |
| Payable to broker for securities purchased | | (37.0) | | | | |
| Total Plan assets | $ | 589.8 | | | | |

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

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

(C) This category represents units of participation in a commingled fund that primarily invested in stocks of international companies and emerging markets.

(D) This category represents units of participation in an investment pool which primarily invests in foreign or domestic bonds, debentures, mortgages, equipment or other trust certificates, notes, obligations issued or guaranteed by the U.S. Government or its agencies, bank certificates of deposit, bankers' acceptances and repurchase agreements, high grade commercial paper and other instruments with money market characteristics with a fixed or variable interest rate. There are no restrictions on redemptions in the common/collective trust.

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

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

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible by the Pension Plan at the measurement date. Instruments classified as Level 1 include investments in common and preferred stocks, U.S. treasury notes and bonds, mutual funds and interest-bearing cash.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability.  Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include corporate fixed income and other securities, mortgage-backed securities, other U.S. Government obligations, commingled fund, a common/collective trust, U.S. municipal bonds, foreign government bonds, a repurchase agreement, money market fund and forward contracts.

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

***Postretirement Benefit Plans***

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members. Regular, full-time, active employees hired prior to February 1, 2000 whose age and years of credited service total or exceed 80 or have attained at least age 55 with 10 or more years of 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. Eligible retirees must contribute such amount as the Company specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. OG&E charges to expense the postretirement benefit costs and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

In January 2011, the Company adopted several amendments to its retiree medical plan. Effective January 1, 2012, the Company's contribution to the medical costs for pre-65 aged eligible retirees are fixed at the 2011 level and the Company covers future annual medical inflationary cost increases up to five percent. Increases in excess of five percent annually are covered by the pre-65 aged retiree in the form of premium increases. Also, effective January 1, 2012, Medicare-eligible retirees are no longer eligible to participate in the retiree medical plan. Instead, the Company began providing Medicare-eligible retirees and their Medicare-eligible spouses an annual fixed contribution to a Company-sponsored health reimbursement arrangement. The contribution was determined based on the Company's expected average 2011 premium for medical and drug coverage. Medicare-eligible retirees are able to purchase individual insurance policies supplemental to Medicare through a third-party administrator and use their health reimbursement arrangement funds for reimbursement of medical premiums and other eligible medical expenses. The effect of these plan amendments was reflected in the Company's 2011 Consolidated Balance Sheet as a reduction to the accumulated postretirement benefit obligation of $91.3 million, an increase in other comprehensive income of $16.9 million and a reduction to OG&E's benefit obligations regulatory asset of $74.4 million.

**Plan Investments**

The following tables summarize the postretirement benefit plans investments that are measured at fair value on a recurring basis at December 31, 2012 and 2011. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2012 and 2011.

| *(In millions)* | December 31, 2012 | Level 1 | Level 3 |
|---|---|---|---|
| Group retiree medical insurance contract (A) | **$ 53.3** | **$ —** | **$ 53.3** |
| Mutual funds investment | | | |
| U.S. equity investments | **6.0** | **6.0** | **—** |
| Money market funds investment | **0.3** | **0.3** | **—** |
| Total Plan investments | **$ 59.6** | **$ 6.3** | **$ 53.3** |

| *(In millions)* | December 31, 2011 | Level 1 | Level 3 |
|---|---|---|---|
| Group retiree medical insurance contract (A) | $ 54.3 | $ — | $ 54.3 |
| Mutual funds investment | | | |
| U.S. equity investments | 5.3 | 5.3 | — |
| Money market funds investment | 0.7 | 0.7 | — |
| Cash | 0.7 | 0.7 | — |
| Total Plan investments | $ 61.0 | $ 6.7 | $ 54.3 |

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

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

The following table summarizes the postretirement benefit plans investments that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

| Year ended December 31 *(In millions)* | | **2012** |
|---|---|---|
| Group retiree medical insurance contract | | |
| Beginning balance | **$** | **54.3** |
| Net unrealized gains related to instruments held at the reporting date | | **5.5** |
| Interest income | | **1.2** |
| Dividend income | | **0.6** |
| Realized gains | | **0.6** |
| Administrative expenses and charges | | **(0.1)** |
| Claims paid | | **(8.8)** |
| Ending balance | **$** | **53.3** |

The following table presents the status of the Company's postretirement benefit plans at December 31, 2012 and 2011. 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 those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

| December 31 *(In millions)* | | **2012** | | 2011 |
|---|---|---|---|---|
| Benefit obligations | **$** | **(301.0)** | $ | (280.6) |
| Fair value of plan assets | | **59.6** | | 61.0 |
| Funded status at end of year | **$** | **(241.4)** | $ | (219.6) |

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. Future health care cost trend rates are assumed to be 8.55 percent in 2013 with the rates trending downward to 4.48 percent by 2028. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

| ONE-PERCENTAGE POINT INCREASE | | | | | | |
|---|---|---|---|---|---|---|
| Year ended December 31 *(In millions)* | | **2012** | | 2011 | | 2010 |
| Effect on aggregate of the service and interest cost components | **$** | **—** | $ | — | $ | 3.1 |
| Effect on accumulated postretirement benefit obligations | | **0.1** | | 0.1 | | 0.7 |

| ONE-PERCENTAGE POINT DECREASE | | | | | | |
|---|---|---|---|---|---|---|
| Year ended December 31 *(In millions)* | | **2012** | | 2011 | | 2010 |
| Effect on aggregate of the service and interest cost components | **$** | **0.1** | $ | 0.1 | $ | 2.5 |
| Effect on accumulated postretirement benefit obligations | | **0.9** | | 0.6 | | 1.6 |

***Medicare Prescription Drug, Improvement and Modernization Act of 2003***

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 expanded coverage for prescription drugs. The following table summarizes the gross benefit payments the Company expects to pay related to its postretirement benefit plans, including prescription drug benefits.

| *(In millions)* | Gross Projected Postretirement Benefit Payments |
|---|---|
| 2013 | $ 15.4 |
| 2014 | 16.3 |
| 2015 | 17.0 |
| 2016 | 17.6 |
| 2017 | 18.1 |
| After 2017 | 94.9 |

***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 2012 and 2011. The benefit obligation for the Company's Pension Plan and the Restoration of Retirement Income Plan represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated postretirement benefit obligation. The accumulated postretirement benefit obligation for the Company's Pension Plan and Restoration of Retirement Income Plan differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2012 was $705.2 million and $12.7 million, respectively. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2011 was $656.1 million and $11.9 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:

| | Pension Plan | | Restoration of Retirement Income Plan | | Postretirement Benefit Plans | |
|---|---|---|---|---|---|---|
| December 31 *(In millions)* | **2012** | 2011 | **2012** | 2011 | **2012** | 2011 |
| Change in Benefit Obligation | | | | | | |
| Beginning obligations | **$ (697.7)** | $ (640.9) | **$ (13.3)** | $ (10.8) | **$ (280.6)** | $ (337.1) |
| Service cost | **(17.9)** | (17.6) | **(1.0)** | (1.0) | **(4.1)** | (3.5) |
| Interest cost | **(30.1)** | (33.3) | **(0.6)** | (0.6) | **(11.9)** | (12.5) |
| Plan amendments | **—** | — | **—** | — | **—** | 91.4 |
| Participants' contributions | **—** | — | **—** | — | **(3.5)** | (8.1) |
| Medicare subsidies received | **—** | — | **—** | — | **(0.5)** | (2.0) |
| Actuarial gains (losses) | **(61.4)** | (48.3) | **(1.8)** | (1.0) | **(12.9)** | (25.7) |
| Benefits paid | **60.0** | 42.4 | **2.2** | 0.1 | **12.5** | 16.9 |
| Ending obligations | **$ (747.1)** | $ (697.7) | **$ (14.5)** | $ (13.3) | **$ (301.0)** | $ (280.6) |
| Change in Plans' Assets | | | | | | |
| Beginning fair value | **$ 589.8** | $ 574.0 | **$ —** | $ — | **$ 61.0** | $ 58.5 |
| Actual return on plans' assets | **61.2** | 8.2 | **—** | — | **4.5** | 2.7 |
| Employer contributions | **35.0** | 50.0 | **2.2** | 0.1 | **2.6** | 6.6 |
| Participants' contributions | **—** | — | **—** | — | **3.5** | 8.1 |
| Medicare subsidies received | **—** | — | **—** | — | **0.5** | 2.0 |
| Benefits paid | **(60.0)** | (42.4) | **(2.2)** | (0.1) | **(12.5)** | (16.9) |
| Ending fair value | **$ 626.0** | $ 589.8 | **$ —** | $ — | **$ 59.6** | $ 61.0 |
| Funded status at end of year | **$ (121.1)** | $ (107.9) | **$ (14.5)** | $ (13.3) | **$ (241.4)** | $ (219.6) |

**Net Periodic Benefit Cost**

| | Pension Plan | | | Restoration of Retirement Income Plan | | | Postretirement Benefit Plans | | |
|---|---|---|---|---|---|---|---|---|---|
| Year ended December 31 *(In millions)* | **2012** | 2011 | 2010 | **2012** | 2011 | 2010 | **2012** | 2011 | 2010 |
| Service cost | **$ 17.9** | $ 17.6 | $ 16.7 | **$ 1.0** | $ 1.0 | $ 0.9 | **$ 4.1** | $ 3.5 | $ 4.3 |
| Interest cost | **30.1** | 33.3 | 31.8 | **0.6** | 0.6 | 0.5 | **11.9** | 12.5 | 17.0 |
| Expected return on plan assets | **(46.0)** | (45.5) | (42.4) | **—** | — | — | **(3.0)** | (5.1) | (6.9) |
| Amortization of transition obligation | **—** | — | — | **—** | — | — | **2.7** | 2.7 | 2.7 |
| Amortization of net loss | **23.8** | 19.2 | 21.3 | **0.4** | 0.4 | 0.3 | **20.6** | 18.3 | 12.1 |
| Amortization of unrecognized prior service cost (A) | **2.2** | 2.4 | 2.4 | **0.7** | 0.7 | 0.7 | **(16.5)** | (16.5) | — |
| Settlement | **—** | — | — | **0.9** | — | — | **—** | — | — |
| Net periodic benefit cost (B) | **$ 28.0** | $ 27.0 | $ 29.8 | **$ 3.6** | $ 2.7 | $ 2.4 | **$ 19.8** | $ 15.4 | $ 29.2 |

(A) Unamortized prior service cost is amortized on a straight-line basis over the average remaining service period to the first eligibility age of participants who are expected to receive a benefit and are active at the date of the plan amendment.

(B) In addition to the $51.4 million, $45.1 million and $61.4 million and of net periodic benefit cost recognized in 2012, 2011 and 2010, respectively, the Company recognized the following:

- an increase in pension expense in 2012, 2011 and 2010 of $8.3 million, $10.8 million and $8.1 million, respectively, to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory liability (see Note 1); and
- an increase in postretirement medical expense in 2012 and 2011 of $0.8 million and $3.5 million, respectively, to maintain the allowable amount to be recovered for postretirement medical expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory liability (see Note 1).

The capitalized portion of the net periodic pension benefit cost was $6.5 million, $6.1 million and $6.5 million at December 31, 2012, 2011 and 2010, respectively. The capitalized portion of the net periodic postretirement benefit cost was $5.5 million, $3.8 million and $6.5 million at December 31, 2012, 2011 and 2010, respectively.

**Rate Assumptions**

| | Pension Plan and Restoration of Retirement Income Plan | | | Postretirement Benefit Plans | | |
|---|---|---|---|---|---|---|
| Year ended December 31 | **2012** | 2011 | 2010 | **2012** | 2011 | 2010 |
| Discount rate | **3.70%** | 4.50% | 5.30% | **3.60%** | 4.50% | 5.30% |
| Rate of return on plans' assets | **8.00%** | 8.00% | 8.50% | **4.00%** | 6.50% | 8.50% |
| Compensation increases | **4.20%** | 4.40% | 4.40% | **N/A** | N/A | N/A |
| Assumed health care cost trend: | | | | | | |
| Initial trend | **N/A** | N/A | N/A | **8.55%** | 8.75% | 8.99% |
| Ultimate trend rate | **N/A** | N/A | N/A | **4.48%** | 4.48% | 5.00% |
| Ultimate trend year | **N/A** | N/A | N/A | **2028** | 2028 | 2020 |

N/A - not applicable

The overall expected rate of return on plan assets assumption remained at 8.00 percent in 2011 and 2012 in determining net periodic benefit cost due to recent returns on the Company's long-term investment portfolio. 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 $2.6 million and $2.4 million at December 31, 2012 and 2011, respectively.

*401(k) Plan*

The Company provides a 401(k) Plan. Each regular full-time employee of the Company or a participating affiliate is eligible to participate in the 401(k) Plan immediately. All other employees of the Company or a participating affiliate are eligible to become participants in the 401(k) Plan after completing one year of service as defined in the 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to certain limitations of the Code. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Code subject to the limitations thereof; or (ii) a contribution made on an after-tax basis. The 401(k) Plan also includes an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her future salary deferral rate to be automatically increased annually on a date and in an amount as specified by the participant in such election.

The 401(k) Plan was amended in October 2009, as discussed previously, whereby participants could select from the options below.

| Employment Date | Option 1 | Option 2 | Option 3 |
|---|---|---|---|
| Before February 1, 2000 | < 20 years of service - 50% Company match up to 6% of compensation | 200% Company match up to 5% of compensation | 100% Company match up to 6% of compensation |
| | > 20 years of service - 75% Company match up to 6% of compensation | 200% Company match up to 5% of compensation | 100% Company match up to 6% of compensation |
| After February 1, 2000 and before December 1, 2009 | 100% Company match up to 6% of compensation | 200% Company match up to 5% of compensation | N/A |
| After December 1, 2009 | 200% Company match up to 5% of compensation | N/A | N/A |

No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Once made, the Company's contribution may be directed to any available investment option in the 401(k) Plan. The Company match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their Company contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Pension Plan, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by the Company or its affiliates. The Company contributed $13.4 million, $12.3 million and $11.4 million in 2012, 2011 and 2010, respectively, to the 401(k) Plan.

***Deferred Compensation Plan***

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

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers. The Company matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on the option the participant elected under the choice provided to eligible employees in the qualified 401(k) Plan discussed above, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after three years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan. Deferrals, plus any Company match, are credited to a recordkeeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. In 2012, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock, and various money market, bond and equity funds. The Company accounts for the contributions related to the Company's executive officers in this plan as Accrued Benefit Obligations and the Company accounts for the contributions related to the Company's directors in this plan as Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. The investment associated with these contributions is accounted for as Other Property and Investments in the Consolidated Balance Sheets. The appreciation of these investments is accounted for as Other Income and the increase in the liability under the plan is accounted for as Other Expense in the Consolidated Statements of Income.

***Supplemental Executive Retirement Plan***

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

## 15. Report of Business Segments

Previously, the Company's business was divided into four segments 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. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. As a result of this change, the Company's business is now divided into three segments for financial reporting purposes as follows: (i) electric utility, (ii) natural gas transportation and storage and (iii) natural gas gathering and processing. Other Operations primarily includes 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, 2012, 2011 and 2010.

| **2012** | Electric Utility | Natural Gas Transportation and Storage | Natural Gas Gathering and Processing | Other Operations | Eliminations | Total |
|---|---|---|---|---|---|---|
| *(In millions)* | | | | | | |
| Operating revenues | **$ 2,141.2** | **$ 639.5** | **$ 1,222.6** | **$ —** | **$ (332.1)** | **$ 3,671.2** |
| Cost of goods sold | **879.1** | **504.9** | **868.7** | **—** | **(334.0)** | **1,918.7** |
| Gross margin on revenues | **1,262.1** | **134.6** | **353.9** | **—** | **1.9** | **1,752.5** |
| Other operation and maintenance | **446.3** | **49.8** | **123.1** | **(17.7)** | **—** | **601.5** |
| Depreciation and amortization | **248.7** | **24.0** | **84.8** | **13.5** | **—** | **371.0** |
| Impairment of assets | **—** | **—** | **0.4** | **—** | **—** | **0.4** |
| Gain on insurance proceeds | **—** | **—** | **(7.5)** | **—** | **—** | **(7.5)** |
| Taxes other than income | **77.7** | **15.7** | **12.6** | **4.2** | **—** | **110.2** |
| Operating income (loss) | **$ 489.4** | **$ 45.1** | **$ 140.5** | **$ —** | **$ 1.9** | **$ 676.9** |
| | | | | | | |
| Total assets | **$ 7,222.4** | **$ 2,330.8** | **$ 1,868.6** | **$ 272.6** | **$ (1,772.2)** | **$ 9,922.2** |
| Capital expenditures (A) | **$ 704.4** | **$ 32.0** | **$ 475.4** | **$ 18.3** | **$ (0.9)** | **$ 1,229.2** |

(A) Includes $78.6 million related to the acquisition of certain gas gathering assets as discussed in Note 3.

| 2011 | Electric Utility | Natural Gas Transportation and Storage | Natural Gas Gathering and Processing | Other Operations | Eliminations | Total |
|---|---|---|---|---|---|---|
| *(In millions)* | | | | | | |
| Operating revenues | $ 2,211.5 | $ 880.1 | $ 1,167.1 | $ — | $ (342.8) | $ 3,915.9 |
| Cost of goods sold | 1,013.5 | 736.0 | 870.7 | — | (342.3) | 2,277.9 |
| Gross margin on revenues | 1,198.0 | 144.1 | 296.4 | — | (0.5) | 1,638.0 |
| Other operation and maintenance | 436.0 | 50.7 | 111.8 | (17.3) | — | 581.2 |
| Depreciation and amortization | 216.1 | 22.0 | 55.6 | 13.4 | — | 307.1 |
| Impairment of assets | — | — | 6.3 | — | — | 6.3 |
| Gain on insurance proceeds | — | — | (3.0) | — | — | (3.0) |
| Taxes other than income | 73.6 | 15.0 | 7.0 | 4.1 | — | 99.7 |
| Operating income (loss) | $ 472.3 | $ 56.4 | $ 118.7 | $ (0.2) | $ (0.5) | $ 646.7 |
| | | | | | | |
| Total assets | $ 6,620.9 | $ 1,836.9 | $ 1,483.8 | $ 166.6 | $ (1,202.2) | $ 8,906.0 |
| Capital expenditures (A) | $ 844.5 | $ 41.1 | $ 572.0 | $ 13.8 | $ (0.6) | $ 1,470.8 |

(A) Includes $200.4 million related to the acquisition of certain gas gathering assets as discussed in Note 3.

| 2010 | Electric Utility | Natural Gas Transportation and Storage | Natural Gas Gathering and Processing | Other Operations | Eliminations | Total |
|---|---|---|---|---|---|---|
| *(In millions)* | | | | | | |
| Operating revenues | $ 2,109.9 | $ 984.8 | $ 1,005.6 | $ — | $ (383.4) | $ 3,716.9 |
| Cost of goods sold | 1,000.2 | 834.5 | 733.3 | — | (380.6) | 2,187.4 |
| Gross margin on revenues | 1,109.7 | 150.3 | 272.3 | — | (2.8) | 1,529.5 |
| Other operation and maintenance | 418.1 | 53.8 | 91.5 | (13.6) | — | 549.8 |
| Depreciation and amortization | 208.7 | 21.2 | 50.1 | 11.3 | — | 291.3 |
| Impairment of assets | — | 0.7 | 0.4 | — | — | 1.1 |
| Taxes other than income | 69.2 | 14.2 | 6.4 | 3.6 | — | 93.4 |
| Operating income (loss) | $ 413.7 | $ 60.4 | $ 123.9 | $ (1.3) | $ (2.8) | $ 593.9 |
| | | | | | | |
| Total assets | $ 5,898.1 | $ 1,316.6 | $ 973.8 | $ 135.4 | $ (654.8) | $ 7,669.1 |
| Capital expenditures | $ 631.6 | $ 72.6 | $ 164.0 | $ 14.1 | $ (2.4) | $ 879.9 |

## 16. Commitments and Contingencies

### *Operating Lease Obligations*

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

| Year ended December 31 *(In millions)* | 2013 | 2014 | 2015 | 2016 | 2017 | After 2017 | Total |
|---|---|---|---|---|---|---|---|
| Operating lease obligations | | | | | | | |
| OG&E railcars | $ 3.2 | $ 2.8 | $ 2.7 | $ 27.3 | $ — | $ — | $ 36.0 |
| OG&E wind farm land leases | 2.0 | 2.1 | 2.1 | 2.1 | 2.4 | 51.2 | 61.9 |
| OGE Energy noncancellable operating lease | 0.3 | 0.8 | 0.8 | 0.8 | 0.8 | 0.7 | 4.2 |
| Enogex noncancellable operating leases | 5.2 | 3.7 | 3.5 | 3.4 | 0.7 | — | 16.5 |
| Total operating lease obligations | $ 10.7 | $ 9.4 | $ 9.1 | $ 33.6 | $ 3.9 | $ 51.9 | $ 118.6 |

Payments for operating lease obligations were $14.2 million, $10.4 million and $10.3 million for the years ended December 31, 2012, 2011 and 2010, respectively.

### OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,389 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. On December 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $22.8 million.

On January 11, 2012, OG&E executed a five-year lease agreement for 135 railcars to replace railcars that have been taken out of service or destroyed. OG&E is also required to maintain all of the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

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

### OG&E Wind Farm Land Lease Agreements

OG&E has wind farm land operating leases for its Centennial, OU Spirit and Crossroads wind farms expiring at various dates. The Centennial lease has rent escalations which increase annually based on the Consumer Price Index. The OU Spirit and Crossroads leases have rent escalations which increase after five and 10 years. Although the leases are cancellable, OG&E is required to make annual lease payments as long as the wind turbines are located on the land. OG&E does not expect to terminate the leases until the wind turbines reach the end of their economic life.

### OGE Energy Noncancellable Operating Lease

On August 29, 2012, OGE Energy executed a five-year lease agreement for office space from September 1, 2013 to August 31, 2018. This lease has rent escalations which increase after five years and allows for leasehold improvements.

### Enogex Noncancellable Operating Leases

Enogex currently occupies 134,219 square feet of office space at its executive offices under a lease that expires March 31, 2017. The lease payments are $11.3 million over the lease term which began April 1, 2012. This lease has rent escalations which increase after five and 10 years if the lease is renewed.

Enogex currently has 17 compression service agreements, of which 10 agreements are on a month-to-month basis, three agreements will expire in 2013, two agreements will expire in 2016 and two agreements will expire in 2017. Enogex also has eight gas treating agreements, of which six agreements are on a month-to-month basis, one agreement will expire in 2013 and one agreement will expire in 2014.

***Other Purchase Obligations and Commitments***

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

| *(In millions)* | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|
| Other purchase obligations and commitments | | | | | | |
| OG&E cogeneration capacity and fixed operation and maintenance payments | $ 87.9 | $ 85.8 | $ 84.5 | $ 82.4 | $ 80.1 | $ 420.7 |
| OG&E expected cogeneration energy payments | 58.6 | 63.8 | 70.5 | 81.0 | 87.3 | 361.2 |
| OG&E minimum fuel purchase commitments | 405.0 | 255.0 | 264.8 | — | — | 924.8 |
| OG&E expected wind purchase commitments | 57.5 | 58.0 | 58.9 | 59.8 | 60.8 | 295.0 |
| OG&E long-term service agreement commitments | 8.0 | 27.8 | 6.7 | 6.2 | 6.4 | 55.1 |
| EER commitments | 11.9 | 10.8 | 4.7 | 0.8 | — | 28.2 |
| Total other purchase obligations and commitments | $ 628.9 | $ 501.2 | $ 490.1 | $ 230.2 | $ 234.6 | $ 2,085.0 |

**Public Utility Regulatory Policy Act of 1978**

At December 31, 2012, OG&E has QF contracts having terms of 15 to 32 years. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978. Stated generally, the Public Utility Regulatory Policy Act of 1978 and the regulations thereunder promulgated by the FERC require OG&E to purchase power generated in a manufacturing process from a QF. The rate for such power to be paid by OG&E was approved by the OCC. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by OG&E; the other is a capacity charge, which OG&E must pay the QF for having the capacity available. However, if no electrical power is made available to OG&E for a period of time (generally three months), OG&E's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is recoverable in rates from customers. For the 320 MW AES-Shady Point, Inc. QF contract and the 120 MW PowerSmith Cogeneration Project, L.P. QF contract, OG&E purchases 100 percent of the electricity generated by the QFs.

For the years ended December 31, 2012, 2011 and 2010, OG&E made total payments to cogenerators of $135.1 million, $140.7 million and $147.3 million, respectively, of which $77.1 million, $78.0 million and $80.7 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as Cost of Goods Sold.

**OG&E Minimum Fuel Purchase Commitments**

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of $585.6 million, $647.6 million and $721.4 million for the years ended December 31, 2012, 2011 and 2010, respectively. OG&E has coal contracts for purchases from January 2012 through December 2015. OG&E has entered into multiple month term natural gas contracts for 26.1 percent of its 2013 annual forecasted natural gas requirements. Additional gas supplies to fulfill OG&E's remaining 2013 natural gas requirements will be acquired through additional requests for proposal in early to mid-2013, along with monthly and daily purchases, all of which are expected to be made at market prices.

**OG&E Wind Purchase Commitments**

OG&E's current wind power portfolio includes: (i) the 120 MW Centennial wind farm, (ii) the 101 MW OU Spirit wind farm, (iii) the 227.5 MW Crossroads wind farm, (iv) access to up to 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma from a 15-year contract OG&E entered into with FPL Energy that expires in 2018, (v) access to up to 150 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with CPV Keenan that expires in 2030, (vi) access to up to 130 MWs of electricity generated at a wind farm in Dewey County, Oklahoma from a 20-year contract OG&E entered into with Edison Mission Energy that expires in 2030 and (vii) access to up to 60 MWs of electricity generated at a wind farm near Blackwell, Oklahoma from a 20-year contract OG&E entered into with NextEra Energy that expires in 2032.

The following table summarizes OG&E's wind power purchases for the years ended December 31, 2012, 2011 and 2010.

| Year ended December 31 *(In millions)* | **2012** | 2011 | 2010 |
|---|---|---|---|
| CPV Keenan | **$ 25.1** | $ 24.5 | $ 3.8 |
| Edison Mission Energy | **20.2** | 8.5 | — |
| FPL Energy | **3.4** | 3.7 | 3.9 |
| NextEra Energy | **0.8** | — | — |
| Total wind power purchased | **$ 49.5** | $ 36.7 | $ 7.7 |

**OG&E Long-Term Service Agreement Commitments**

In July 2004, OG&E acquired a 77 percent interest in the McClain Plant. As part of that acquisition, OG&E became subject to an existing long-term parts and service maintenance contract for the upkeep of the natural gas-fired combined cycle generation facility. The contract was initiated in December 1999, and runs for the earlier of 96,000 factored-fired hours or 4,800 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2015. The contract requires payments based on both a fixed and variable cost component, depending on how much the McClain Plant is used.

In September 2008, OG&E acquired a 51 percent interest in the Redbud Plant. As part of that acquisition, OG&E became subject to an existing long-term parts and service maintenance contract for the upkeep of the natural gas-fired combined cycle generation facility. The contract was initiated in January 2001, and runs for the earlier of 120,000 factored-fired hours or 4,500 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2027. The contract requires payments based on both a fixed and variable cost component, depending on how much the Redbud Plant is used.

**EER Commitments**

In 2004, EER entered into a firm transportation service agreement with Cheyenne Plains, who operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas, for 60,000 decatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a 10-year term beginning with the in-service date of the Cheyenne Plains Pipeline in March 2005 with an annual demand fee of $7.4 million. Effective March 1, 2007, EER and Cheyenne Plains amended the firm transportation service agreement to provide for EER to turn back 20,000 decatherms/day of its capacity beginning in January 2008 for the remainder of the term.

In 2006, Enogex entered into a firm capacity agreement with MEP for a primary term of 10 years (subject to possible extension) that gives MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP capacity agreement is currently 272 MMcf/d, with the quantity subject to being increased by mutual agreement pursuant to the capacity agreement. In 2009, EER entered into a firm transportation service agreement with MEP for 10,000 decatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a five-year term beginning with the in-service date of the MEP pipeline in June 2009 with an annual demand fee of $2.1 million.

***Environmental Laws and Regulations***

The activities of OG&E and Enogex are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way it can handle or dispose of their wastes, requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. OG&E and Enogex believe that their operations are in substantial compliance with current Federal, state and local environmental standards.

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

OG&E and Enogex are managing several significant uncertainties about the scope and timing for the acquisition, installation and operation of additional pollution control equipment and compliance costs for a variety of the EPA rules that are being challenged in court. OG&E and Enogex are unable to predict the financial impact of these matters with certainty at this time. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations" for a discussion of the Company's environmental matters.

***Pipeline Safety Legislation***

On December 13, 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which the President signed into law on January 3, 2012. Among other things, the law requires additional verification of pipeline infrastructure records by Enogex and other intrastate and interstate pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. Where records are inadequate to confirm the maximum allowable operating pressure, the PHMSA will require the operator to re-confirm the maximum allowable operating pressure, a process that could cause temporary or permanent limitations on throughput for affected pipelines. This law required PHMSA to direct pipeline operators to verify the maximum allowable operating pressure of their pipelines by July 3, 2012, and to submit documentation to PHMSA by July 3, 2013. This law also raises the maximum penalty for violating pipeline safety rules to $0.2 million per violation per day up to $2.0 million for a related series of violations.

In addition, this law requires PHMSA to issue reports and/or, if appropriate, develop new regulations, addressing a variety of subjects, including: (1) requiring pipeline owners and operators to install excess-flow valves in certain circumstances; (2) requiring pipeline owners and operators to use automatic or remote-controlled shut-off valves in certain circumstances; (3) requiring pipeline owners and operators to test to confirm the strength of previously untested transmission lines located within high consequence areas and operating at a pressure greater than 30 percent of specified minimum yield stress; (4) requiring pipeline owners and operators to notify the National Response Center of an accident or incident at the earliest practicable moment (but not later than one hour) after confirming that an accident or incident has occurred; (5) expanding integrity management requirements beyond high consequence areas; and (6) applying the Federal pipeline safety regulations to onshore gathering lines that are not currently subject to the Federal pipeline safety regulations. This law prescribes various deadlines for PHMSA to act on these issues.

At this time, the Company is not able to estimate the capital, operating or other costs that may be required to comply with this law and any related PHMSA regulations that may be promulgated, but such costs could be significant.

***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 or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. At the present time, based on currently available information, except as otherwise stated above, in Note 17 below, in Item 3 of Part I and under "Environmental Laws and Regulations" in Item 7 of Part II of this Form 10-K, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

## 17. Rate Matters and Regulation

**Regulation and Rates**

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's wholesale electric tariffs, transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the U.S. Department of Energy has jurisdiction over some of OG&E's facilities and operations. In 2012, 87 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and five percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of OGE Energy. The order required that, among other things, (i) OGE Energy permit the OCC access to the books and records of OGE Energy and its affiliates relating to transactions with OG&E, (ii) OGE Energy employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) OGE Energy 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 OGE Energy and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates.

**Completed Regulatory Matters**

***OG&E Contract and Wind Energy Purchase Agreement Filing***

On December 1, 2011, OG&E filed an application with the OCC requesting approval of a 20-year agreement that is intended to provide wind power to help meet the current and future power generation needs of Oklahoma State University. The project called for OG&E to contract with NextEra Energy to build a 60 MW wind farm near Blackwell, Oklahoma, to support the Oklahoma State University project in which NextEra Energy built, owns and operates the wind farm and OG&E purchases the electric output. On February 22, 2012, OG&E, the Attorney General and the Public Utility Division of the OCC signed a settlement agreement whereby the stipulating parties requested that the OCC issue an order approving the agreement for electric service with Oklahoma State University. On March 12, 2012, OG&E received an order from the OCC approving the settlement agreement. Pursuant to the terms of the power purchase agreement between OG&E and NextEra Energy, OG&E has been purchasing the electric output of the wind farm since November 2012 and uses that power to provide service to Oklahoma State University and its other retail customers. The wind farm was fully in service in December 2012.

***OG&E SPP Transmission Projects***

The SPP is a regional transmission organization under the jurisdiction of the FERC that was created to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity. The SPP does not build transmission though the SPP's tariff contains rules that govern the transmission construction process. Transmission owners complete the construction and then own, operate and maintain transmission assets within the SPP region. When the SPP Board of Directors approves a project, the transmission provider in the area where the project is needed currently has the first obligation to build; however, the process for deciding which entity constructs and owns a project may change as a result of FERC Order. No. 1000 discussed below.

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

In 2007, the SPP notified OG&E to construct 44 miles of a new 345 kilovolt transmission line originating at OG&E's existing Sooner 345 kilovolt substation and proceeding generally in a northerly direction to the Oklahoma/Kansas Stateline (referred to as the Sooner-Rose Hill project). At the Oklahoma/Kansas Stateline, the line connects to the companion line constructed in Kansas by Westar Energy. The transmission line was placed in service in April 2012. The total capital expenditures associated with this project were $45 million.

In January 2009, OG&E received notification from the SPP to begin construction on 50 miles of a new 345 kilovolt transmission line and substation upgrades at OG&E's Sunnyside substation, among other projects. In April 2009, Western Farmers Electric Cooperative assigned to OG&E the construction of 50 miles of line designated by the SPP to be built by Western Farmers Electric Cooperative. The new line extends from OG&E's Sunnyside substation near Ardmore, Oklahoma, 123.5 miles to the Hugo substation owned by Western Farmers Electric Cooperative near Hugo, Oklahoma. The transmission line was completed in April 2012. The total capital expenditures associated with this project were $157 million.

As discussed below, the OCC approved a settlement agreement in OG&E's 2011 Oklahoma rate case filing that included an expedited procedure for recovering the costs of the two projects. On July 31, 2012, OG&E filed an application with the OCC requesting an order authorizing recovery for the two projects through the SPP transmission systems additions rider. On October 2, 2012, all parties signed a settlement agreement in this matter which stated: (i) the parties agree not to oppose requested relief sought by OG&E, (ii) OG&E will host meetings to discuss the SPP’s transmission planning process, including any future transmission projects for which OG&E has received a notice to construct from the SPP, and (iii) there will be opportunities for parties to provide input related to transmission planning studies that the SPP performs to identify future transmission projects. On October 25, 2012, the OCC issued an order approving the settlement agreement and granting OG&E cost recovery for the two projects. OG&E initiated cost recovery beginning with the first billing cycle in November 2012.

***OG&E 2011 Oklahoma Rate Case Filing***

On July 28, 2011, OG&E filed its application with the OCC requesting an annual rate increase of $73.3 million, or a 4.3 percent increase in its rates. OG&E requested a return on equity of 11.0 percent based on a common equity percentage of 53.0 percent. In its application, OG&E requested recovery of increases in its operating costs and to begin earning on approximately $500 million of new capital investments made on behalf of its Oklahoma customers during the previous two and one-half years. On July 2, 2012, OG&E and other parties associated with its rate increase reached a settlement agreement in this matter. On July 9, 2012, the OCC issued an order approving the settlement agreement in this matter. Key terms of the settlement agreement included: (i) an annual net increase of approximately $4.3 million in OG&E's rates to its Oklahoma retail customers, (ii) OG&E's Oklahoma retail authorized return on equity of 10.2 percent, (iii) the rate of return under various recovery riders previously approved by the OCC, including riders for OG&E's smart grid implementation and Crossroads wind farm, is based on OG&E's actual debt and equity ratios as reflected in OG&E's application and a 10.2 percent return on equity, (iv) depreciation rates were implemented in the same month new customer rates went into effect, (v) the pension and postretirement medical cost tracker remains in effect, (vi) a procedure was established to expedite the recovery of the cost of specified high-voltage transmission projects and (vii) extension of funding for OG&E's system hardening program. OG&E expects the impact of the rate increase on its customers and service territory to be minimal as the rate increase will be more than offset by lower fuel costs attributable to prior fuel over recoveries from lower than forecasted fuel costs. OG&E implemented the new rates effective in early August.

***OG&E Smart Grid Project***

On December 17, 2010, OG&E filed an application with the APSC requesting pre-approval for system-wide deployment of smart grid technology and a recovery rider, including a credit for the Smart Grid grant awarded by the U.S. Department of Energy under the American Recovery and Reinvestment Act of 2009. On June 22, 2011, OG&E reached a settlement agreement with all the parties in this matter. OG&E and the other parties in this matter agreed to ask the APSC to approve the settlement agreement including the following: (i) pre-approval of system-wide deployment of smart grid technology in Arkansas and authorization for OG&E to begin recovering the prudently incurred costs of the Arkansas system-wide deployment of smart grid technology through a rider mechanism that will become effective in accordance with the order approving the settlement agreement; (ii) cost recovery through the rider would commence when all of the smart meters to be deployed in Arkansas are in service; (iii) OG&E guarantees that customers will receive certain operations and maintenance cost reductions resulting from the smart grid deployment as a credit to the recovery rider; and (iv) the stranded costs associated with OG&E's existing meters which are being replaced by smart meters will be accumulated in a regulatory asset and recovered in base rates beginning after an order is issued in OG&E's next general rate case. On August 3, 2011, the APSC issued an order in this matter approving the settlement agreement. On November 5, 2012, OG&E filed a revised smart grid recovery rider rate schedule. On December 13, 2012, the APSC issued an order in this matter approving the revised smart grid recovery rider to be effective beginning with the first billing cycle in January 2013 through December 2013. OG&E began recovering the estimated capital costs of $14 million and associated operation and maintenance costs for deployment of smart grid technology, along with incremental costs for web portal access and education of $0.8 million. The APSC also found that the prudence of OG&E’s smart grid expenditures will be determined in OG&E's next Arkansas rate case and that revenues collected under the rider are subject to refund, with interest, only in the event that the APSC determines that OG&E's smart grid expenditures were not prudent. The costs recoverable from Oklahoma customers for system-wide deployment of smart grid technology and implementing the smart grid pilot program were capped at $366.4 million (inclusive of the U.S. Department of Energy grant award amount) subject to an offset for any recovery of those costs from Arkansas customers and are currently being recovered through a rider which will remain in effect until the smart grid project costs are included in base rates in OG&E's next general rate case. This project was completed in late 2012 and the smart grid project costs did not exceed $366.4 million.

***OG&E Demand and Energy Efficiency Program Filing***

On July 2, 2012, OG&E filed an application with the OCC requesting approval of OG&E's 2013 demand portfolio, the authorization to recover the program costs, lost revenues associated with any achieved energy, demand savings and performance based incentives through the demand program rider and the recovery of costs associated with research and development investments. On July 16, 2012, OG&E filed an amended application which modified various calculations to reflect the rate of return authorized by the OCC in OG&E's 2011 rate case order and provided for consideration of a peak time rebate program. On December 20, 2012, the OCC approved a settlement with all parties in this matter. Key terms of the settlement included (i) approval of the program budgets proposed by OG&E and an additional amount of approximately $7 million over the three-year period for the energy efficiency programs, (ii) approval of OG&E’s proposed Demand Program Rider tariff, (iii) the recovery through the Demand Program Rider of the increased program costs and the net lost revenues, incentives and research and development investments requested by OG&E, with the exception of lost revenues resulting from the Integrated Volt Var Control program (automated intelligence to control voltage and power on the distribution lines) and incentives for the SmartHours® and Integrated Volt Var Control demand response programs, (iv) recovery of the program costs on a levelized basis over the three-year period, (v) consideration of implementing a peak time rebate program in 2015 and (vi) the periodic filing of additional reports. The Demand Program Rider became effective on January 1, 2013.

***OG&E Fuel Adjustment Clause Review for Calendar Year 2010***

The OCC routinely reviews the costs recovered from customers through OG&E’s fuel adjustment clause. On August 19, 2011, the OCC Staff filed an application to review OG&E’s fuel adjustment clause for calendar year 2010, including the prudence of OG&E’s electric generation, purchased power and fuel procurement costs. OG&E responded by filing direct testimony and the minimum filing review package on October 18, 2011. On September 26, 2012, the administrative law judge recommended that the OCC find that for the calendar year 2010 OG&E's generation, purchase power and fuel procurement processes and costs, including the cost of replacement power for the Sooner 2 outage, were prudent and no disallowance (as discussed below) for any of these expenses is warranted. On January 31, 2013, the OCC issued an order approving the administrative law judge's recommendation. Previously, the Oklahoma Industrial Energy Consumers recommended that the OCC disallow recovery of approximately $44 million of costs previously recovered through OG&E's fuel adjustment clause. These recommendations were based on allegations that OG&E's lower cost coal-fired generation was underutilized, that OG&E failed to aggressively pursue purchasing power at a cost lower than its marginal cost of generation and that OG&E should be found imprudent related to an unplanned outage at OG&E's Sooner 2 coal unit in November and December 2010. Previously, the OCC Staff recommended approval of OG&E's actions related to utilization of coal plants and practices related to purchasing power but recommended that OG&E refund $3 million to customers because of the Sooner 2 outage.

***Enogex 2011 Fuel Filing***

On February 28, 2011, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the upcoming fuel year (April 1, 2011 through March 31, 2012). Along with the revised fuel percentages, Enogex also requested authority to revise its statement of operating conditions to permanently change the annual filing date to February 28. On July 6, 2012, Enogex submitted a compliance filing to synchronize the 2011 fuel filing with the revised statement of operating conditions filed on May 31, 2012 in compliance with the FERC's order approving Enogex's 2011 Section 311 rate case settlement. In October 2012, the FERC accepted Enogex's proposed zonal fuel percentages.

***Enogex 2012 Fuel Filing***

On February 24, 2012, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the 2012 fuel year (April 1, 2012 through March 31, 2013). On July 6, 2012, Enogex submitted a compliance filing to synchronize the 2012 fuel filing with the revised statement of operating conditions filed on May 31, 2012 in compliance with the FERC's order approving Enogex's 2011 Section 311 rate case settlement. In October 2012, the FERC accepted Enogex's proposed zonal fuel percentages.

***Enogex Storage Statement of Operating Conditions Filing***

On August 31, 2010, Enogex filed a new statement of operating conditions applicable to storage services with the FERC that replaced Enogex's existing storage statement of operating conditions effective July 30, 2010. Among other things, the new storage statement of operating conditions updates the general terms and conditions for providing storage services. On December 7, 2012, the FERC issued an order approving Enogex's revised storage statement of operating conditions, effective August 31, 2010.

***Enogex FERC Section 311 2011 Rate Case***

On January 28, 2011, Enogex submitted a new rate filing to the FERC to set the maximum rate for a new firm Section 311 transportation service in the West Zone of its system and to revise the currently effective maximum rates for Section 311 interruptible transportation service in the East Zone and West Zone. Along with establishing the rate for a new firm service in the West Zone, Enogex's filing requested a decrease in the maximum interruptible zonal rates in the West Zone and to retain the currently effective rates for firm and interruptible services in the East Zone. Enogex reserved the right to implement the higher rates for firm and interruptible services in the East Zone supported by the cost of service to the extent an expeditious settlement agreement cannot be reached in the proceeding. Enogex proposed that the rates be placed into effect on March 1, 2011. On January 10, 2012, Enogex filed a settlement agreement with the FERC. On May 4, 2012, the FERC issued an order approving the settlement agreement in this matter, subject to the submission of a compliance filing to place the settlement rates into effect as of March 1, 2011, which compliance filing was subsequently filed on May 31, 2012. The FERC also requested that Enogex file a revised statement of operating conditions, which was subsequently filed on May 31, 2012. As part of the settlement agreement in this matter, Enogex made refunds of $0.2 million to affected customers on June 15, 2012 and submitted a report to the FERC on July 6, 2012 showing the refund payment calculation. On February 21, 2013, the FERC issued an order approving the refund report.

**Pending Regulatory Matters**

***FERC Order No. 1000, Final Rule on Transmission Planning and Cost Allocation***

On July 21, 2011, the FERC issued Order No. 1000, which revised the FERC's existing regulations governing the process for planning enhancements and expansions of the electric transmission grid in a particular region, along with the corresponding process for allocating the costs of such expansions. Order No. 1000 leaves to individual regions to determine whether a previously-approved project is subject to reevaluation and is therefore governed by the new rule.

Order No. 1000 requires, among other things, public utility transmission providers, such as the SPP, to participate in a process that produces a regional transmission plan satisfying certain standards, and requires that each such regional process consider transmission needs driven by public policy requirements (such as state or Federal policies favoring increased use of renewable energy resources). Order No. 1000 also directs public utility transmission providers to coordinate with neighboring transmission planning regions. In addition, Order No. 1000 establishes specific regional cost allocation principles and directs public utility transmission providers to participate in regional and interregional transmission planning processes that satisfy these principles.

On the issue of determining how entities are to be selected to develop and construct the specific transmission projects, Order No. 1000 directs public utility transmission providers to remove from the FERC-jurisdictional tariffs and agreements provisions that establish any Federal "right of first refusal" for the incumbent transmission owner (such as OG&E) regarding transmission facilities selected in a regional transmission planning process, subject to certain limitations. However, Order No. 1000 is not intended to affect the right of an incumbent transmission owner (such as OG&E) to build, own and recover costs for upgrades to its own transmission facilities, and Order No. 1000 does not alter an incumbent transmission owner's use and control of existing rights of way. Order No. 1000 also clarifies that incumbent transmission owners may rely on regional transmission facilities to meet their reliability needs or service obligations. The SPP currently has a "right of first refusal" for incumbent transmission owners and this provision has played a role in OG&E being selected by the SPP to build various transmission projects in Oklahoma. These changes to the "right of first refusal" apply only to "new transmission facilities," which are described as those subject to evaluation or reevaluation (under the applicable local or regional transmission planning process) subsequent to the effective date of the regulatory compliance filings required by the rule, which were filed on November 13, 2012.

OGE Energy cannot, at this time, determine the precise impact of Order No. 1000 on OG&E. OG&E has filed a petition for review in the D.C. Circuit relating to the same matter. Nevertheless, at the present time, OGE Energy has no reason to believe that the implementation of Order No. 1000 will impact OG&E's transmission projects currently under development and construction for which OG&E has received a notice to proceed from the SPP.

***OG&E Market-Based Rate Authority***

On June 29, 2012, OG&E filed its triennial market power update with the FERC to retain its market-based rate authorization in the SPP's energy imbalance service market but to surrender its market-based rate authorization for any market-based rate sales outside the SPP's energy imbalance service market. A FERC order is pending.

***OG&E Fuel Adjustment Clause Review for Calendar Year 2011***

On July 31, 2012, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2011 fuel adjustment clause and for a prudence review of OG&E's electric generation, purchased power and fuel procurement processes and costs in calendar year 2011. OG&E filed the necessary information and documents needed to satisfy the OCC's minimum filing requirement rules on October 1, 2012. On December 19, 2012, witnesses for the OCC Staff filed responsive testimony recommending that the OCC approve OG&E's fuel adjustment clause costs and recoveries for the calendar year 2011 and recommending that the OCC find that OG&E's electric generation, purchased power, fuel procurement and other fuel related practices, policies and decisions during calendar year 2011 were fair, just and reasonable and prudent. The Oklahoma Industrial Energy Consumers filed a statement of position on December 19, 2012 and did not challenge OG&E's application of its fuel adjustment clause or prudency. The Oklahoma Industrial Energy Consumers reserved its right to file rebuttal testimony, cross examine witnesses and amend its statement of position should circumstances change or additional information becomes available in the course of this proceeding. On January 7, 2013, the Oklahoma Attorney General filed a statement of position stating that after reviewing the case information the Attorney General has no reason at this time to dispute the findings of the OCC Staff. A hearing in this matter is scheduled for April 4, 2013.

***OG&E Crossroads Wind Farm***

As previously reported, OG&E signed memoranda of understanding in February 2010 for approximately 197.8 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the Crossroads wind farm. Also as part of this project, on June 16, 2011, OG&E entered into an interconnection agreement with the SPP for the Crossroads wind farm which allowed the Crossroads wind farm to interconnect at 227.5 MWs. On August 31, 2012, OG&E filed an application with the APSC requesting approval to recover the Arkansas portion of the costs of the Crossroads wind farm through a rider until such costs are included in OG&E's base rates as part of its next general rate proceeding. On December 14, 2012, the APSC Staff filed testimony recommending that the APSC find that the Crossroads wind farm is in the public interest and that it approve interim recovery through the Energy Cost Recovery Rider effective August 31, 2012. OG&E concurred with the APSC Staff's recommendations. On January 16, 2013, the APSC granted a motion made by OG&E and the APSC Staff to cancel the hearing previously scheduled and issue an order based on the filed record. On February 22, 2013, the APSC directed OG&E to respond to two questions in order to complete the record upon which they may rule. OG&E believes it is reasonable to expect a final order from the APSC by the end of the first quarter.

***OG&E Fuel Adjustment Clause Review for Calendar Year 2009 Related to Enogex Gas Transportation and Storage Agreement***

As previously reported, under the terms of a settlement agreement reached in 2011 regarding the prudency of OG&E's fuel adjustment clause for 2009, OG&E agreed to hire a third party expert to evaluate its prospective gas transportation and storage needs and to identify options for meeting those needs. Upon completion of the third party evaluation, OG&E agreed to file a cause to address the third party's evaluation, recommendations and conclusions. On January 31, 2013, OG&E filed a cause that included OG&E's response to the final evaluations and conclusions of the third party consultant, Black & Veatch, and OG&E's assessment of transportation and storage needs for the next three to five years.

Also, as part of this matter, on August 9, 2012, OG&E filed an application with the OCC requesting: (i) an order finding that a one-year extension to April 30, 2014 of OG&E's gas transportation and storage agreement with Enogex is prudent, (ii) a waiver of the OCC's competitive procurement rules and (iii) finding that the one-year extension of the gas transportation and storage agreement complies with the OCC's affiliate transaction rules. On September 14, 2012, OG&E filed a settlement agreement in which all parties to this matter agreed to the one-year extension of the Enogex contract and cost recovery from ratepayers at the rates currently in effect. On October 25, 2012, the OCC issued an order approving the settlement agreement.

## 18. Quarterly Financial Data (Unaudited)

Due to the seasonal fluctuations and other factors of the Company's businesses, the operating results for interim periods are not necessarily indicative of the results that may be expected for the year. In the Company's opinion, the following quarterly financial data includes all adjustments, consisting of normal recurring adjustments, necessary to fairly present such amounts. Summarized consolidated quarterly unaudited financial data is as follows:

| Quarter ended (*In millions, except per share data*) | | March 31 | June 30 | September 30 | December 31 | Total |
|---|---|---|---|---|---|---|
| Operating revenues | **2012** | **$ 840.7** | **$ 855.0** | **$ 1,113.4** | **$ 862.1** | **$ 3,671.2** |
| | 2011 | $ 840.5 | $ 978.1 | $ 1,212.1 | $ 885.2 | $ 3,915.9 |
| Operating income | **2012** | **$ 98.3** | **$ 177.3** | **$ 304.0** | **$ 97.3** | **$ 676.9** |
| | 2011 | $ 67.9 | $ 182.2 | $ 299.7 | $ 96.9 | $ 646.7 |
| Net income | **2012** | **$ 47.5** | **$ 101.6** | **$ 192.4** | **$ 43.5** | **$ 385.0** |
| | 2011 | $ 29.7 | $ 109.3 | $ 181.4 | $ 43.2 | $ 363.6 |
| Net income attributable to OGE Energy | **2012** | **$ 37.1** | **$ 93.9** | **$ 185.5** | **$ 38.5** | **$ 355.0** |
| | 2011 | $ 24.8 | $ 103.0 | $ 178.7 | $ 36.4 | $ 342.9 |
| Basic earnings per average common share attributable to OGE Energy common shareholders (A) | **2012** | **$ 0.38** | **$ 0.95** | **$ 1.88** | **$ 0.39** | **$ 3.60** |
| | 2011 | $ 0.25 | $ 1.05 | $ 1.82 | $ 0.37 | $ 3.50 |
| Diluted earnings per average common share attributable to OGE Energy common shareholders (A) | **2012** | **$ 0.38** | **$ 0.95** | **$ 1.87** | **$ 0.39** | **$ 3.58** |
| | 2011 | $ 0.25 | $ 1.04 | $ 1.80 | $ 0.37 | $ 3.45 |

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

## 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, 2012 and 2011, and the related consolidated statements of income, comprehensive income, cash flows and changes in stockholders' equity for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of OGE Energy Corp. at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), OGE Energy Corp.'s internal control over financial reporting as of December 31, 2012, 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 27, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 27, 2013

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

None.

**Item 9A. Controls and Procedures.**

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

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

**Management's Report on Internal Control Over Financial Reporting**

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

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2012. 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, 2012, the Company's internal control over financial reporting is effective based on those criteria.

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

| | |
|---|---|
| /s/ Peter B. Delaney | /s/ Scott Forbes |
| Peter B. Delaney, Chairman of the Board, President<br>and Chief Executive Officer | Scott Forbes, Controller<br>and Chief Accounting Officer |
| /s/ Sean Trauschke | |
| Sean Trauschke, Vice President<br>and Chief Financial 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, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). OGE Energy Corp.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, OGE Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, 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, 2012 and 2011, and the related consolidated statements of income, comprehensive income, cash flows and changes in stockholders' equity for each of the three years in the period ended December 31, 2012 of OGE Energy Corp. and our report dated February 27, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 27, 2013

**Item 9B. Other Information.**

None.

## PART III

**Item 10. Directors, Executive Officers and Corporate Governance.**

**Code of Ethics Policy**

OGE Energy maintains a code of ethics for our chief executive officer and senior financial officers, including the chief financial officer and chief accounting officer, which is available for public viewing on OGE Energy's web site address www.oge.com under the heading "Investor Relations", "Corporate Governance." The code of ethics will be provided, free of charge, upon request. OGE Energy intends to satisfy the disclosure requirements under Section 5, Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the code of ethics by posting such information on its web site at the location specified above. OGE Energy will also include in its proxy statement information regarding the Audit Committee financial experts.

**Item 11. Executive Compensation.**

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

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

**Item 14. Principal Accounting Fees and Services.**

Items 10 through 14 (other than Item 10 information regarding the Code of Ethics) are omitted pursuant to General Instruction G of Form 10-K, because the Company will file copies of a definitive proxy statement with the Securities and Exchange Commission on or about March 31, 2013. Such proxy statement is incorporated herein by reference.

## PART IV

**Item 15. Exhibits, Financial Statement Schedules.**

**(a) 1. Financial Statements**

The following Consolidated Financial Statements are included in Part II, Item 8 of this Annual Report:

- Consolidated Statements of Income for the years ended December 31, 2012, 2011 and 2010
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2012, 2011 and 2010
- Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010
- Consolidated Balance Sheets at December 31, 2012 and 2011
- Consolidated Statements of Capitalization at December 31, 2012 and 2011
- Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2012, 2011 and 2010
- Notes to Consolidated Financial Statements
- Report of Independent Registered Public Accounting Firm (Audit of Financial Statements)
- Management's Report on Internal Control Over Financial Reporting
- Report of Independent Registered Public Accounting Firm (Audit of Internal Control)

**2. Financial Statement Schedule (included in Part IV)**

- Schedule II - Valuation and Qualifying Accounts

All other schedules have been omitted since the required information is not applicable or is not material, or because the information required is included in the respective Consolidated Financial Statements or Notes thereto.

**3. Exhibits**

| Exhibit No. | Description |
|---|---|
| 2.01 | Purchase Agreement, dated as of May 14, 1999, by and between Tejas Gas, LLC and Enogex Inc. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 1999 (File No. 1-12579) and incorporated by reference herein) |
| 2.02 | Asset Purchase Agreement, dated as of August 18, 2003 by and between OG&E and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed August 20, 2003 (File No. 1-12579) and incorporated by reference herein) |
| 2.03 | Amendment No. 1 to Asset Purchase Agreement, dated as of October 22, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein) |
| 2.04 | Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.04 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein) |
| 2.05 | Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.05 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein) |
| 2.06 | Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.06 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein) |
| 2.07 | Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.07 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein) |
| 2.08 | Amendment No. 6 to Asset Purchase Agreement, dated as of March 12, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 2.09 | Amendment No. 7 to Asset Purchase Agreement, dated as of April 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 2.10 | Amendment No. 8 to Asset Purchase Agreement, dated as of May 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 2.11 | Amendment No. 9 to Asset Purchase Agreement, dated as of June 2, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 2.12 | Amendment No. 10 to Asset Purchase Agreement, dated as of June 17, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 2.13 | Purchase and Sale Agreement, dated as of January 21, 2008, entered into by and among Redbud Energy I, LLC, Redbud Energy II, LLC and Redbud Energy III, LLC and OG&E. (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein) |
| 2.14 | Asset Purchase Agreement, dated as of January 21, 2008, entered into by and among OG&E, the Oklahoma Municipal Power Authority and the Grand River Dam Authority. (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein) |
| 2.15 | Investment Agreement dated as of October 5, 2010 by and between OGE Energy Corp., Enogex Holdings LLC and Bronco Midstream Holdings, LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed October 6, 2010 (File No. 1-12579) and incorporated by reference herein) |
| 3.01 | Copy of Restated OGE Energy Corp. Certificate of Incorporation. (Filed as Exhibit 3.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12579) and incorporated by reference herein) |
| 3.02 | Copy of Amended OGE Energy Corp. By-laws. (Filed as Exhibit 3.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2010 (File No. 1-12579) and incorporated by reference herein) |
| 4.01 | Trust Indenture dated October 1, 1995, from OG&E to Boatmen's First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to Registration Statement No. 33-61821 and incorporated by reference herein) |

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| 4.02 | Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed July 17, 1997 (File No. 1-1097) and incorporated by reference herein) |
| 4.03 | Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed April 16, 1998 (File No. 1-1097) and incorporated by reference herein) |
| 4.04 | Supplemental Indenture No. 5 dated as of October 24, 2001, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.06 to Registration Statement No. 333-104615 and incorporated by reference herein) |
| 4.05 | Supplemental Indenture No. 6 dated as of August 1, 2004, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed August 6, 2004 (File No 1-1097) and incorporated by reference herein) |
| 4.06 | Indenture dated as of November 1, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.01 to OGE Energy's Form 8-K filed November 12, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 4.07 | Supplemental Indenture No. 1 dated as of November 9, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.02 to OGE Energy's Form 8-K filed November 12, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 4.08 | Supplemental Indenture No. 7 dated as of January 1, 2006 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.08 to OG&E's Form 8-K filed January 6, 2006 (File No. 1-1097) and incorporated by reference herein) |
| 4.09 | Supplemental Indenture No. 8 dated as of January 15, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed January 31, 2008 (File No. 1-1097) and incorporated by reference herein) |
| 4.10 | Supplemental Indenture No. 9 dated as of September 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed September 9, 2008 (File No. 1-1097) and incorporated by reference herein) |
| 4.11 | Supplemental Indenture No. 10 dated as of December 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed December 11, 2008 (File No. 1-1097) and incorporated by reference herein) |
| 4.12 | Issuing and Paying Agency Agreement dated as of June 15, 2009, by and between Enogex LLC and UMB Bank, N.A. (Filed as Exhibit 4.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2009 (File No. 1-12579) and incorporated by reference herein) |
| 4.13 | Issuing and Paying Agency Agreement dated as of November 15, 2009, by and between Enogex LLC and UMB Bank, N.A. (Filed as Exhibit 4.15 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein) |
| 4.14 | Supplemental Indenture No. 11 dated as of June 1, 2010 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed June 8, 2010 (File No. 1-1097) and incorporated by reference herein) |
| 4.15 | Supplemental Indenture No. 12 dated as of May 15, 2011 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed May 27, 2011 (File No. 1-1097) and incorporated by reference herein) |
| 10.01* | OGE Energy's 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy's Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein) |
| 10.02* | OGE Energy's 2003 Stock Incentive Plan. (Filed as Annex A to OGE Energy's Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein) |
| 10.03 | Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 9, 2012 (File No. 1-12579) and incorporated by reference herein) |
| 10.04 | Amended and Restated Facility Operating Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 10.05 | Amended and Restated Ownership and Operation Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 10.06 | Operating and Maintenance Agreement for the Transmission Assets of the McClain Generating Facility dated as of August 25, 2003 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.05 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 10.07* | Amendment No. 1 to OGE Energy's 2003 Stock Incentive Plan. (Filed as Exhibit 10.23 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein) |

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| 10.08 | Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement dated as of May 1, 2003 between OG&E and Enogex. [Confidential treatment has been requested for certain portions of this exhibit.] (Filed as Exhibit 10.24 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 10.09 | Firm Transportation Service Agreement Rate Schedule FT dated as of December 1, 2004 between OGE Energy Resources, Inc. and Cheyenne Plains Gas Pipeline Company, L.L.C. (Filed as Exhibit 10.25 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 10.10* | Form of Performance Unit Agreement under OGE Energy's 2008 Stock Incentive Plan. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12579) and incorporated by reference herein) |
| 10.11* | Form of Split Dollar Agreement. (Filed as Exhibit 10.32 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein) |
| 10.12 | Credit agreement dated as of December 13, 2011, by and between OGE Energy, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed December 19, 2011 (File No. 1-12579) and incorporated by reference herein) |
| 10.13 | Credit agreement dated as of December 13, 2011, by and between OG&E, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 19, 2011 (File No. 1-12579) and incorporated by reference herein) |
| 10.14* | Amendment No. 1 to OGE Energy's 1998 Stock Incentive Plan. (Filed as Exhibit 10.26 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein) |
| 10.15* | Amendment No. 2 to OGE Energy's 2003 Stock Incentive Plan. (Filed as Exhibit 10.27 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein) |
| 10.16 | Capacity Lease Agreement dated as of December 11, 2006, by and between Enogex, Inc. and Midcontinent Express Pipeline LLC. [Confidential treatment has been requested for certain portions of this exhibit.] (Filed as Exhibit 10.30 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein) |
| 10.17 | Ownership and Operating Agreement, dated as of January 21, 2008, entered into by and among OG&E, the Oklahoma Municipal Power Authority and the Grand River Dam Authority. (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein) |
| 10.18 | Credit agreement dated as of December 13, 2011, by and between Enogex LLC, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.03 to OGE Energy's Form 8-K filed December 19, 2011 (File No. 1-12579) and incorporated by reference herein) |
| 10.19* | OGE Energy Supplemental Executive Retirement Plan, as amended and restated. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein) |
| 10.20* | OGE Energy Restoration of Retirement Income Plan, as amended and restated. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein) |
| 10.21* | OGE Energy Deferred Compensation Plan, as amended and restated. (Filed as Exhibit 10.05 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein) |
| 10.22* | Amendment No. 3 to OGE Energy's 2003 Stock Incentive Plan. (Filed as Exhibit 10.06 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein) |
| 10.23* | Amendment No. 2 to OGE Energy's 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein) |
| 10.24* | OGE Energy's 2008 Stock Incentive Plan. (Filed as Annex A to OGE Energy's Proxy Statement for the 2008 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein) |
| 10.25* | OGE Energy's 2008 Annual Incentive Compensation Plan. (Filed as Annex B to OGE Energy's Proxy Statement for the 2008 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein) |
| 10.26* | Form of Employment Agreement for all existing and future officers of the Company relating to change of control. (Filed as Exhibit 10.28 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein) |
| 10.27* | Form of Restricted Stock Agreement under OGE Energy's 2008 Stock Incentive Plan. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended September 30, 2008 (File No. 1-12579) and incorporated by reference herein) |

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| 10.28 | Agreement, dated February 17, 2010, between OG&E and Oklahoma Department of Environmental Quality. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed February 23, 2010 (File No. 1-12579) and incorporated by reference herein) |
| 10.29* | Amendment No. 1 to OGE Energy's Restoration of Retirement Income Plan. (Filed as Exhibit 10.40 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein) |
| 10.30* | Amendment No. 1 to OGE Energy's Deferred Compensation Plan. (Filed as Exhibit 10.33 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein) |
| 10.31 | Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 1, 2010 (File No. 1-12579) and incorporated by reference herein) |
| 10.32 | Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Crossroads wind farm application. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed July 1, 2010 (File No. 1-12579) and incorporated by reference herein) |
| 10.33 | Copy of Settlement Agreement with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed May 19, 2011 (File No. 1-12579) and incorporated by reference herein) |
| 10.34 | Copy of Settlement Agreement with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed June 28, 2011 (File No. 1-12579) and incorporated by reference herein) |
| 10.35* | Amendment No. 2 to OGE Energy's Deferred Compensation Plan. (Filed as Exhibit 10.41 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein) |
| 10.36* | Amendment No. 3 to OGE Energy's Deferred Compensation Plan. (Filed as Exhibit 10.39 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein) |
| 10.37* | Amendment No. 1 to OGE Energy's 2008 Stock Incentive Plan. (Filed as Exhibit 10.40 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein) |
| 10.38* | Director Compensation. |
| 10.39* | Executive Officer Compensation. |
| 10.40 | Term loan agreement dated as of August 2, 2012, by and between Enogex LLC and JP Morgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Documentation Agent and Union Bank, N.A. and U.S. Bank National Association, as Co-Syndication Agents. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed August 7, 2012 (File No. 1-12579) and incorporated by reference herein). |
| 12.01 | Calculation of Ratio of Earnings to Fixed Charges. |
| 21.01 | Subsidiaries of the Registrant. |
| 23.01 | Consent of Ernst & Young LLP. |
| 24.01 | Power of Attorney. |
| 31.01 | Certifications Pursuant to Rule 13a-14(a)/15d-14(a) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.01 | Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 99.01 | Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995. |
| 99.02 | Copy of APSC order with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 22, 2011 (File No. 1-12579) and incorporated by reference herein) |
| 99.03 | Copy of OCC Order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 7, 2010 (File No. 1-12579) and incorporated by reference herein) |
| 99.04 | Copy of OCC Order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Crossroads wind farm application. (Filed as Exhibit 99.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2010 (File No. 1-12579) and incorporated by reference herein) |
| 99.05 | Description of Capital Stock. (Filed as Exhibit 99.07 to OGE Energy's Form 10-K for the year ended December 31, 2010 (File No. 1-12579) and incorporated by reference herein) |
| 101.INS | XBRL Instance Document. |
| 101.SCH | XBRL Taxonomy Schema Document. |
| 101.PRE | XBRL Taxonomy Presentation Linkbase Document. |
| 101.LAB | XBRL Taxonomy Label Linkbase Document. |

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| 101.CAL | XBRL Taxonomy Calculation Linkbase Document. |
| 101.DEF | XBRL Definition Linkbase Document. |

* Represents executive compensation plans and arrangements.

**OGE ENERGY CORP.**

**SCHEDULE II - Valuation and Qualifying Accounts**

| Description | Balance at Beginning of Period | Additions: Charged to Costs and Expenses | Deductions (A) | Balance at End of Period |
|---|---|---|---|---|
| | *(In millions)* | | | |
| **Balance at December 31, 2010** | | | | |
| Reserve for Uncollectible Accounts | $ 2.4 | $ 2.6 | $ 3.1 | $ 1.9 |
| **Balance at December 31, 2011** | | | | |
| Reserve for Uncollectible Accounts | $ 1.9 | $ 5.8 | $ 3.9 | $ 3.8 |
| **Balance at December 31, 2012** | | | | |
| Reserve for Uncollectible Accounts | **$ 3.8** | **$ 3.3** | **$ 4.5** | **$ 2.6** |

(A) Uncollectible accounts receivable written off, net of recoveries.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, and State of Oklahoma on the 27th day of February, 2013.

**OGE ENERGY CORP.**
(Registrant)

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

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this Report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ Peter B. Delaney<br>Peter B. Delaney | Principal Executive Officer and Director; | February 27, 2013 |
| /s/ Sean Trauschke<br>Sean Trauschke | Principal Financial Officer; and | February 27, 2013 |
| /s/ Scott Forbes<br>Scott Forbes | Principal Accounting Officer. | February 27, 2013 |
| James H. Brandi | Director; | |
| Wayne H. Brunetti | Director; | |
| Luke R. Corbett | Director; | |
| John D. Groendyke | Director; | |
| Kirk Humphreys | Director; | |
| Robert Kelley | Director; | |
| Robert O. Lorenz | Director; | |
| Judy R. McReynolds | Director; and | |
| Leroy C. Richie | Director. | |
| /s/ Peter B. Delaney<br>By Peter B. Delaney (attorney-in-fact) | | February 27, 2013 |

**Exhibit 10.38**

**OGE Energy Corp.**
**Director Compensation**

Compensation of non-officer directors of the Company in 2012 included an annual retainer fee of $128,600, of which $45,600 was payable in cash in monthly installments and $83,000 was deposited in the director's account under the Company's Deferred Compensation Plan in December 2012 and converted to 1,460.239 common stock units based on the closing price of the Company's Common Stock on December 3, 2012. All non-officer directors received $2,000 for each Board meeting and $2,000 for each committee meeting attended. The lead director received an additional $15,000 cash retainer in 2012. The chairman of the Audit Committee received an additional $10,000 cash retainer in 2012. The chairmen of the Compensation and Nominating and Corporate Governance Committees received an additional $5,000 annual cash retainer in 2012. Each chairman of a board committee also received a meeting fee of $2,000 for each meeting (either in person or by phone) with management to address committee matters. Each member of the Audit Committee also received an additional annual retainer of $5,000. These amounts represent the total fees paid to directors in their capacities as directors of the Company and OG&E in 2012.

Under the Company's Deferred Compensation Plan, non-officer directors may defer payment of all or part of their attendance fees and the cash portion of their annual retainer fee, which deferred amounts are credited to their account as of the first day of the month in which the deferred amounts otherwise would have been paid. Amounts credited to the accounts are assumed to be invested in one or more of the investment options permitted under the Company's Deferred Compensation Plan. In 2012, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock, and various money market, bond and equity funds. When an individual ceases to be a director of the Company, all amounts credited under the Company's Deferred Compensation Plan are paid in cash in a lump sum or installments. In certain circumstances, participants may also be entitled to in-service withdrawals from the Company's Deferred Compensation Plan.

In November 2012, the Compensation Committee met to consider director compensation. At that meeting, the Compensation Committee increased the additional annual retainer for the chairmen of the Compensation and Nominating and Corporate Governance Committees for 2013 to $7,500 from $5,000, increased the additional annual retainer for the chairman of the Audit Committee for 2013 to $12,500 from $10,000 and increased the additional annual retainer for the lead director for 2013 to $17,500 from $15,000. At that meeting, the Compensation Committee also increased the portion of the annual retainer payable in December 2012 and deposited in the director's account under the Company's Deferred Compensation Plan for 2012 to $83,000 from $73,000. The other components of director compensation remained unchanged.

**Exhibit 10.39**

**OGE Energy Corp.**
**Executive Officer Compensation**

**Executive Compensation**

In November 2012, the Compensation Committee of the OGE Energy Corp. board of directors took actions setting executives' salaries, target amount of annual bonus awards and target amounts of long-term compensation awards for 2013. Executive compensation was set by the Compensation Committee after consideration of, among other things, individual performance and market-based data on compensation for executives with similar duties. Payouts of 2013 annual bonus targets and long-term awards are dependent on achievement of specified corporate goals that will be established by the Compensation Committee at a subsequent meeting, and no officer is assured of any payout.

**Salary**

The Compensation Committee established the base salaries for its senior executive group. The salaries for 2013 for the OGE Energy officers who are expected to be named in the Summary Compensation Table in OGE Energy's 2013 Proxy Statement are as follows:

| Executive Officer | 2013 Base Salary |
|---|---|
| Peter B. Delaney, Chairman, President and Chief Executive Officer | $920,400 |
| Sean Trauschke, Vice President and Chief Financial Officer | $504,712 |
| E. Keith Mitchell, President and Chief Operating Officer of Enogex Holdings; President of Enogex LLC | $365,700 |
| Stephen E. Merrill, Chief Operating Officer of Enogex LLC | $324,996 |
| Jean C. Leger, Jr., Vice President - Utility Operations of OG&E | $308,275 |

**Establishment of 2013 Annual Incentive Awards**

As stated above, at its November 2012 meeting, the Compensation Committee approved the target amount of annual incentive awards, expressed as a percentage of salary, with the officer having the ability, depending upon achievement of the 2013 corporate goals to be set by the Compensation Committee at a subsequent meeting, to receive from 0 percent to 150 percent of such targeted amount. For 2013, the targeted amount ranged from 65 percent to 100 percent of the approved 2013 base salary for the executive officers in the above table.

**Establishment of Long-Term Awards**

At its November 2012 meeting, the Compensation Committee also approved the level of target long-term incentive awards, expressed as a percentage of salary, with the officer having the ability to receive from 0 percent to 200 percent of such targeted amount at the end of a three-year performance period depending upon achievement of the corporate goals to be set by the Compensation Committee at a subsequent meeting. For 2013, the targeted amount ranged from 115 percent to 245 percent of the approved 2013 base salary for the executive officers in the above table.

**Other Benefits**

**Retirement Benefits**. A significant amount of the Company's employees hired before December 1, 2009, including executive officers, are eligible to participate in the Company's Pension Plan and certain employees are eligible to participate in the Company's Restoration of Retirement Income Plan that enables participants, including executive officers, to receive the same benefits that they would have received under the Company's Pension Plan in the absence of limitations imposed by the Federal tax laws. In addition, the supplemental executive retirement plan, which was adopted in 1993, provides a supplemental executive retirement plan in order to attract and retain lateral hires or other executives designated by the Compensation Committee of the Company's Board of Directors who may not otherwise qualify for a sufficient level of benefits under the Company's Pension Plan and Restoration of Retirement Income Plan. Mr. Delaney is the only employee, including executive officers, who participates in the supplemental executive retirement plan. Mr. Delaney's participation in the supplemental executive retirement plan was the result of arms-length bargaining between Mr. Delaney and the Company at the time of his hire in April 2002 as Executive Vice President of the Company.

Almost all employees of the Company, including executive officers, also are eligible to participate in our 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to certain limitations of the Code. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Code subject to the limitations thereof; or (ii) a contribution made on an after-tax basis. The 401(k) Plan also includes an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her future salary deferral rate to be automatically increased annually on a date and in an amount as specified by the participant in such election. In October 2009, the Company's Pension Plan and the Company's 401(k) Plan were amended, effective January 1, 2010 to provide eligible employees a choice to select a future retirement benefit combination from the Company's Pension Plan and the Company's 401(k) Plan.

The 401(k) Plan was amended in October 2009, as discussed previously, whereby participants could select from the options below.

| Employment Date | Option 1 | Option 2 | Option 3 |
|---|---|---|---|
| Before February 1, 2000 | < 20 years of service - 50% Company match up to 6% of compensation | 200% Company match up to 5% of compensation | 100% Company match up to 6% of compensation |
| | > 20 years of service - 75% Company match up to 6% of compensation | 200% Company match up to 5% of compensation | 100% Company match up to 6% of compensation |
| After February 1, 2000 and before December 1, 2009 | 100% Company match up to 6% of compensation | 200% Company match up to 5% of compensation | N/A |
| After December 1, 2009 | 200% Company match up to 5% of compensation | N/A | N/A |

No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Once made, the Company's contribution may be directed to any available investment option in the 401(k) Plan. The Company match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their Company contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Pension Plan, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by the Company or its affiliates.

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees' 401(k) Plan contributions as well as offering this plan to be competitive in the marketplace. Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers.

The Company matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on the option the participant elected under the choice provided to eligible employees in the qualified 401(k) Plan discussed above, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after three years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan.

Deferrals, plus any Company match, are credited to a recordkeeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. In 2012, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock, and various money market, bond and equity funds.

Normally, payments under the deferred compensation plan begin within one year after retirement. For these purposes, normal retirement age is 65 and the minimum age to qualify for early retirement is age 55 with at least five years of service. Benefits will be paid, at the election of the participant, either in a lump sum or a stream of annual payments for up to 15 years, or a combination thereof. Participants whose employment terminates before they qualify for retirement will receive their vested account balance in one lump sum following termination as provided in the plan. Participants also will be entitled to pre- and post-retirement survivor benefits. If the participant dies while in employment before retirement, his or her beneficiary will receive a payment of the account balance plus a supplemental survivor benefit equal to two times the total amount of base salary and bonuses deferred under the plan. If the participant dies following retirement, his or her beneficiary will continue to receive the remaining vested account balance. Additionally, eligible surviving spouses will be entitled to a lifetime survivor annuity payable annually. The amount of the annuity is based on 50 percent of the participant's account balance at retirement, the spouse's age and actuarial assumptions established by the Company's Benefits Committee.

At any time prior to retirement, a participant may withdraw all or part of amounts attributable to his or her vested account balance under the deferred compensation plan at December 31, 2004, subject to a penalty of 10 percent of the amount withdrawn. In addition, at the time of the initial deferral election, a participant may elect to receive one or more in-service distributions on specified dates without penalty. Hardship withdrawals, without penalty, of amounts attributable to a participant's vested account balance as of December 31, 2004 may also be permitted at the discretion of the Company's Benefits Committee.

**Perquisites.** The Company also offers executive officers a limited amount of perquisites. These include payment of social membership dues at dining and country clubs for certain executive officers, an annual physical exam for all executive officers, a relocation program and, in the case of Mr. Delaney, use of a Company car. In reviewing the perquisites and the benefits under the supplemental executive retirement plan, 401(k) Plan, Deferred Compensation Plan, Pension Plan and Restoration of Retirement Income Plan, the Compensation Committee sought in 2012 to provide participants with benefits at least commensurate with those offered by other utilities of comparable size.

**Change-of-Control Provisions and Employment Agreements.** None of the Company's executive officers has an employment agreement with the Company. Each of the executive officers has a change of control agreement that becomes effective upon a change of control. If an executive officer's employment is terminated by the Company "without cause" following a change of control, the executive officer is entitled to the following payments: (i) all accrued and unpaid compensation and a prorated annual bonus and (ii) a severance payment equal to 2.99 times the sum of such officer's (a) annual base salary and (b) highest recent annual bonus. The change of control agreements are considered to be double trigger agreements because payment will only be made following a change of control and termination of employment. The 2.99 times multiple for change-of-control payments was selected because at the time it was considered standard. Although many companies also include provisions for tax gross-up payments to cover any excise taxes on excess parachute payments, the Company's Board of Directors decided not to include this additional benefit in the Company's agreements. Instead, under the Company's agreements if the excise tax would be imposed, the change-of-control payments will be reduced to a point where no excise tax would be payable, if such reduction would result in a greater after-tax payment.

In addition, pursuant to the terms of the Company's incentive compensation plans, upon a change of control, all stock options and restricted stock will vest immediately and, for a 60-day period following the change of control, executive officers may surrender their options and receive in return a cash payment equal to the excess of the change of control price (as defined) over the exercise price; all performance units will vest and be paid out immediately in cash as if the applicable performance goals had been satisfied at target levels; and any annual incentive award outstanding for the year in which the participant's termination occurs for any reason, other than cause, within 24 months after the change of control will be paid in cash at target level on a prorated basis.

**Exhibit 12.01**

**OGE Energy Corp.**
**Ratio of Earnings to Fixed Charges**

| Year ended December 31 *(In millions)* | **2012** | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Earnings: | | | | | |
| Pre-tax income | **$ 520.1** | $ 524.3 | $ 461.4 | $ 382.2 | $ 338.6 |
| Add: Fixed charges | **174.4** | 161.8 | 150.1 | 154.5 | 130.0 |
| Subtotal | **694.5** | 686.1 | 611.5 | 536.7 | 468.6 |
| | | | | | |
| Subtract: | | | | | |
| Allowance for borrowed funds used during construction | **3.5** | 10.4 | 5.5 | 8.3 | 4.0 |
| Other capitalized interest | **4.5** | 8.7 | 2.5 | 6.3 | 3.5 |
| Total earnings | **686.5** | 667.0 | 603.5 | 522.1 | 461.1 |
| | | | | | |
| Fixed Charges: | | | | | |
| Interest on long-term debt | **163.4** | 154.8 | 141.8 | 143.6 | 106.6 |
| Interest on short-term debt and other interest charges | **8.7** | 5.2 | 5.9 | 8.4 | 21.0 |
| Calculated interest on leased property | **2.3** | 1.8 | 2.4 | 2.5 | 2.4 |
| Total fixed charges | **$ 174.4** | $ 161.8 | $ 150.1 | $ 154.5 | $ 130.0 |
| | | | | | |
| Ratio of Earnings to Fixed Charges | **3.94** | 4.12 | 4.02 | 3.38 | 3.55 |

**Exhibit 21.01**

**OGE Energy Corp.**
**Subsidiaries of the Registrant**

| Name of Subsidiary | Jurisdiction of Incorporation | Percentage of Ownership |
|---|---|---|
| Oklahoma Gas and Electric Company | Oklahoma | 100.0 |
| OGE Enogex Holdings LLC | Delaware | 100.0 |
| Enogex Holdings LLC | Delaware | 79.9 |
| Enogex LLC | Delaware | 79.9 |
| Enogex Gathering & Processing LLC | Oklahoma | 79.9 |
| Enogex Products LLC | Oklahoma | 79.9 |
| Enogex Gas Gathering LLC | Oklahoma | 79.9 |

The above listed subsidiaries have been consolidated in the Registrant's financial statements. Certain of the Company's subsidiaries have been omitted from the list above in accordance with Rule 1-02(w) of Regulation S-X.

**Exhibit 23.01**

**Consent of Independent Registered Public Accounting Firm**

We consent to the incorporation by reference in the Registration Statement (Form S-8 No. 333-71327) pertaining to the 1998 stock incentive plan, the Registration Statement (Form S-8 No. 333-92423) pertaining to the deferred compensation plan, the Registration Statement (Form S-8 No. 333-104497) pertaining to the employees' stock ownership and retirement savings plan, the Registration Statement (Form S-8 No. 333-115735) pertaining to the 2003 stock incentive plan, the Registration Statement (Form S-8 No. 333-152022) pertaining to the 2008 stock incentive plan, the Registration Statement (Form S-3ASR No. 333-178093) pertaining to the dividend reinvestment and stock purchase plan and the Registration Statement (Form S-3ASR No. 333-166572) pertaining to common stock and preferred share purchase rights and debt securities, of our reports dated February 27, 2013, with respect to the consolidated financial statements and schedule of OGE Energy Corp., and the effectiveness of internal control over financial reporting of OGE Energy Corp., included in this Annual Report (Form 10-K) for the year ended December 31, 2012.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 27, 2013

**Exhibit 24.01**

**Power of Attorney**

WHEREAS, OGE ENERGY CORP., an Oklahoma corporation (herein referred to as the "Company"), is about to file with the Securities and Exchange Commission, under the provisions of the Securities Exchange Act of 1934, as amended, its annual report on Form 10-K for the year ended December 31, 2012; and

WHEREAS, each of the undersigned holds the office or offices in the Company herein-below set opposite his or her name, respectively;

NOW, THEREFORE, each of the undersigned hereby constitutes and appoints PETER B. DELANEY, SEAN TRAUSCHKE and SCOTT FORBES and each of them individually, his or her attorney with full power to act for him or her and in his or her name, place and stead, to sign his name in the capacity or capacities set forth below to said Form 10-K and to any and all amendments thereto, and hereby ratifies and confirms all that said attorney may or shall lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this 13th day of February, 2013.

| | |
|---|---|
| Peter B. Delaney, Chairman, Principal Executive Officer and Director | /s/ Peter B. Delaney |
| James H. Brandi, Director | /s/ James H. Brandi |
| Wayne H. Brunetti, Director | /s/ Wayne H. Brunetti |
| Luke R. Corbett, Director | /s/ Luke R. Corbett |
| John D. Groendyke, Director | /s/ John D. Groendyke |
| Kirk Humphreys, Director | /s/ Kirk Humphreys |
| Robert Kelley, Director | /s/ Robert Kelley |
| Robert O. Lorenz, Director | /s/ Robert O. Lorenz |
| Judy R. McReynolds, Director | /s/ Judy R. McReynolds |
| Leroy C. Richie, Director | /s/ Leroy C. Richie |
| Sean Trauschke, Principal Financial Officer | /s/ Sean Trauschke |
| Scott Forbes, Principal Accounting Officer | /s/ Scott Forbes |

STATE OF OKLAHOMA )
) SS
COUNTY OF OKLAHOMA )

On the date indicated above, before me, Kelly Hamilton-Coyer, Notary Public in and for said County and State, the above named directors and officers of OGE ENERGY CORP., an Oklahoma corporation, known to me to be the persons whose names are subscribed to the foregoing instrument, severally acknowledged to me that they executed the same as their own free act and deed.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal on the 13th day of February, 2013.

/s/ Kelly Hamilton-Coyer
By: Kelly Hamilton-Coyer
*Notary Public*

My commission expires:
July 6, 2013

**Exhibit 31.01**

**CERTIFICATIONS**

I, Peter B. Delaney, certify that:

1. I have reviewed this annual report on Form 10-K of OGE Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2013

/s/ Peter B. Delaney

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

**Exhibit 31.01**

**CERTIFICATIONS**

I, Sean Trauschke, certify that:

1. I have reviewed this annual report on Form 10-K of OGE Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2013

/s/ Sean Trauschke

Sean Trauschke
Vice President and Chief Financial Officer

**Exhibit 32.01**

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

In connection with the Annual Report of the Company on Form 10-K for the period ended December 31, 2012, as filed with the Securities and Exchange Commission (the "Report"), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 27, 2013

/s/ Peter B. Delaney

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

/s/ Sean Trauschke

Sean Trauschke
Vice President and Chief Financial Officer

**Exhibit 99.01**

## OGE Energy Corp. Cautionary Factors

The Private Securities Litigation Reform Act of 1995 provides a "safe harbor" for forward-looking statements to encourage such disclosures without the threat of litigation providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements have been and will be made in written documents and oral presentations of the Company. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used in the Company's documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential", "project" and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company's actual results to differ materially from the forward-looking statements include, but are not limited to, the following, by segment:

***Consolidated (including Electric Utility, Natural Gas Transportation and Storage and Natural Gas Gathering and Processing)***

- Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, transmission, currency, interest rate and warranty risks;
- Risks associated with PRM strategies intended to mitigate exposure to adverse movement in the prices of natural gas on both a global and regional basis, including commodity price changes, market supply shortages, interest rate changes and counterparty default;
- General economic conditions, including the availability of credit, access to existing lines of credit, access to the commercial paper markets, actions of rating agencies and their impact on capital expenditures and our ability to access the capital markets, inflation rates and monetary fluctuations;
- Customer business conditions including demand for their products or services and supply of labor and materials used in creating their products and services currently and in the future;
- Financial or regulatory accounting principles or policies imposed by the Financial Accounting Standards Board, the Securities and Exchange Commission, the FERC, state public utility commissions; the regional state committee which regulates the SPP; state entities which regulate natural gas transmission, gathering and processing and similar entities with regulatory oversight;
- Environmental laws, safety laws or other regulations passed by the EPA, the Oklahoma Department of Environmental Quality or other governing agencies that may impact the cost of operations or restrict or change the way the Company operates its facilities;
- Availability or cost of capital, including changes in interest rates, market perceptions of the utility and energy-related industries, the Company or any of its subsidiaries or security ratings;
- Employee workforce factors including changes in key executives and employee retention;
- Social attitudes regarding the utility, natural gas and power industries;
- Identification of suitable investment opportunities to enhance shareowner returns and achieve long-term financial objectives through business acquisitions and divestitures;
- Some future investments made by the Company could take the form of noncontrolling interests which would limit the Company's ability to control the development or operation of an investment;
- Increased pension and healthcare costs;
- Costs and other effects of legal and administrative proceedings, settlements, investigations, claims and matters, including but not limited to those described in Note 16 of Notes to Consolidated Financial Statements in this Form 10-K;
- Technological developments, changing markets and other factors that result in competitive disadvantages and create the potential for impairment of existing assets;
- The cost of protecting assets against, or damage due to, terrorism or cyber attacks and other catastrophic events; and
- Other business or investment considerations that may be disclosed from time to time in the Company's Securities and Exchange Commission filings or in other publicly disseminated written documents.

***Electric Utility Segment***

- Increased competition in the utility industry, including effects of decreasing margins as a result of competitive pressures; industry restructuring initiatives; transmission system operation and/or administration initiatives;

recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, unusual maintenance or repairs; unanticipated changes to fossil fuel, natural gas or coal supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints;
- Rate-setting policies or procedures of regulatory entities, including environmental externalities;
- Approval of future regulatory filings with the OCC or the APSC; and
- Discontinuance of accounting principles for certain types of rate-regulated activities.

***Natural Gas Transportation and Storage and Natural Gas Gathering and Processing Segments***

- Increased competition in the natural gas processing industry, including effects of decreasing margins as a result of competitive pressures, commodity exposure and nature of competitors entering the industry; and
- Cold weather extremes that may impact the ability of producing customers to maintain gas deliveries, or the quality of such deliveries, into the pipeline system.

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