OGE ENERGY CORP
Form 10-K
February 16, 2007

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

FORM 10-K
(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2006

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____

Commission File Number: 1-12579

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

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

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

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

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange
Rights to Purchase Series A Preferred Stock	New York Stock Exchange

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated Filer x Accelerated Filer o Non-Accelerated Filer o

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

At June 30, 2006, the last business day of the registrant s most recently completed second fiscal quarter, the aggregate market value of shares of common stock held by non-affiliates was $3,176,094,786 based on the number of shares held by non-affiliates (90,667,850) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $35.03.

At January 31, 2007, 91,349,801 shares of common stock, par value $0.01 per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company s 2007 annual meeting of stockholders is incorporated by reference into Part III of this Form 10-K.

OGE ENERGY CORP.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2006

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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 materially. 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, 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, actions of rating agencies and their impact on capital expenditures;
- OGE Energy Corp. s (collectively, with its subsidiaries, the Company) ability and the ability of its subsidiaries to obtain financing on favorable terms;
- prices and availability of electricity, coal, natural gas and natural gas liquids, each on a stand-alone basis and in relation to each other;
- business conditions in the energy industry;
- 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 (including the approval of future regulatory filings with the Oklahoma Corporation Commission (OCC) or the Arkansas Public Service Commission (APSC) related to its proposed construction of a new power plant and the outcome of Oklahoma Gas and Electric Company s (OG&E) current Federal Energy Regulatory Commission (FERC) audit) 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 regulated accounting principles under Financial Accounting Standards Board Statement of Financial Accounting Standard (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation ;
- 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.

PART I

Item 1. Business.

THE COMPANY

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 two business segments, the Electric Utility and the Natural Gas Pipeline segments. For financial information regarding these segments, see Note 16 of Notes to Consolidated Financial Statements.

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 gas business in 1928 and is no longer engaged in the gas distribution business.

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries (Enogex) and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. Enogex s focus is to utilize its gathering, processing, transportation and storage capacity to execute physical, financial and service transactions to capture margins across different natural gas related commodities, locations or time periods. The vast majority of Enogex s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Prior to October 31, 2005, Enogex owned, through a 75 percent interest in the NOARK Pipeline System Limited Partnership (NOARK), a controlling interest in and operated Ozark Gas Transmission, L.L.C. (OGT), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. On October 31, 2005, Enogex sold its interest in Enogex Arkansas Pipeline Corporation (EAPC), which held its NOARK interest. Also, during the third quarter of 2005, Enogex Compression Company, LLC (Enogex Compression) sold it majority interest in Enerven Compression Services, LLC (Enerven), a joint venture focused on the rental of natural gas compression assets. In May 2006, Enogex Gas Gathering, L.L.C. (Gathering), a wholly-owned subsidiary of Enogex Inc., sold certain gas gathering assets in the Kinta, Oklahoma, area (the Kinta Assets). The EAPC and Enerven businesses and the sale of the Kinta Assets have been reported as discontinued operations in the Company s Consolidated Financial Statements and are discussed further in Note 8 of Notes to Consolidated Financial Statements. In December 2006, Enogex entered into a joint venture arrangement with a third party. The joint venture, Atoka Midstream LLC, intends to construct, own and operate a gathering system and processing plant and related facilities relating to production in certain areas in southeastern Oklahoma. Enogex holds its 50 percent membership interest in Atoka Midstream LLC through Enogex Atoka LLC (Enogex Atoka), a wholly-owned subsidiary of Enogex Inc. Enogex Atoka will act as the managing member and operator of the facilities owned by the joint venture.

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.

Company Strategy

The Company s vision is to be a regional utility-focused energy business recognized for operational excellence and strong financial performance. The Company intends to execute its vision by focusing on its regulated electric utility business and unregulated midstream gas business. As explained below, the Company intends to maintain the majority of its assets in the regulated utility business complemented by its natural gas pipeline business. The Company s long-term financial goals include earnings growth of four to five percent on a weather-normalized basis, an annual total return in the top third of its peer group, dividend growth, maintenance of a dividend payout ratio consistent with its peer group, maintenance of strong credit ratings and appropriate returns on invested capital. The Company believes it can accomplish these financial goals by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and maintaining strong regulatory and legislative relationships.

OG&E has been focused on its Customer Savings and Reliability Plan, which provides for increased investment at the utility to improve reliability and meet load growth, replace infrastructure equipment, replace aging transmission and distribution system and deploy newer technology that improves operational, financial and environmental performance. As part of this plan, OG&E purchased, for approximately $160 million, a 77 percent interest in the 520 megawatt (MW) natural gas-fired combined cycle NRG McClain Station (the McClain Plant) in July 2004. Capacity payment savings from

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reduced cogeneration payments and fuel savings from the McClain Plant will be utilized to help mitigate the price increases associated with this investment. Also, as part of this plan, on February 20, 2006, OG&E entered into an agreement to engineer, procure and construct a wind generation energy system for a 120 MW wind farm (Centennial) in northwestern Oklahoma. The wind farm was fully in service in January 2007. Through December 31, 2006, OG&E has spent approximately $171.1 million related to the Centennial wind farm. On January 17, 2007, OG&E sent notice to the OCC to trigger the Centennial wind farm rider for the first billing cycle in February 2007. OG&E has announced a six-year construction initiative that is estimated to include up to $3.3 billion in major projects designed to expand capacity, enhance reliability and improve environmental performance. The first part of this initiative involved OG&E entering into an agreement for the proposed construction of a 950 MW coal unit at OG&E s existing Sooner plant location near Red Rock, Oklahoma. OG&E expects construction to begin in 2007 and is targeting the completion of the power plant in the 2011/2012 timeframe. OG&E s share of the projected $1.8 billion construction cost for the plant will be about $759 million. OG&E s six-year construction initiative also includes strengthening and expanding the electric transmission, distribution and substation systems and replacing aging infrastructure. Other projects involve installing new emission-control equipment at existing OG&E power plants to help meet OG&E s commitment to meet environmental requirements. OG&E also expects to incur a significant amount of capital and operating expenditures in the next several years to comply with current and future environmental laws and regulations. For additional information regarding the above items and other regulatory matters, see Note 18 of Notes to Consolidated Financial Statements.

Enogex plans to continue to implement improvements to enhance long-term financial performance of its mid-continent assets through more efficient operations and effective commercial management of the assets. In addition, Enogex is seeking to diversify its gathering, processing and transportation businesses principally by expanding into other geographic areas that are complementary with the Company s strategic capabilities. In August 2006, Enogex completed a project to expand its gathering pipeline capacity on the west side of its system in western Oklahoma and the Texas Panhandle that should enable Enogex to benefit from growth opportunities in that marketplace. Enogex continues to consider additional opportunities to expand this project. In addition to focusing on growing its earnings, Enogex has reduced its exposure to changes in commodity prices and minimized its exposure to keep-whole processing arrangements. Enogex s profitability increased significantly from 2003 to 2006 due to the performance improvement plan initiated in 2002 as well as an overall favorable business environment coupled with higher commodity prices. While the Company believes substantial progress has been achieved, additional opportunities remain. Enogex continues to review its work processes, evaluate the rationalization of assets, negotiate better terms for both new contracts and replacement contracts, manage costs and pursue opportunities for organic growth, all in an effort to further improve its cash flow and net income, while at the same time decreasing the volatility associated with commodity prices. Enogex s marketing business, which concentrates principally on origination of physical sales of natural gas, has expanded into the Gulf Coast and Rocky Mountain markets. Also, Enogex s marketing business utilizes a strategy that seeks to minimize the amount of capital employed and to complement better the natural gas pipeline business. The Company expects to continue to pursue a disciplined approach to continuous improvement and efficiency of operations. As discussed above, during 2005 and 2006, Enogex sold its interests in EAPC and Enerven and the Kinta Assets and will continue to review its asset portfolio and seek to divest underperforming or non-strategic assets. Also, on December 15, 2006, Enogex announced that it had entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC for a primary term of 10 years (subject to possible extensions) for certain capacity on the Enogex system. The leased capacity provided for in this agreement is up to 0.5 billion cubic feet (Bcf) per day and is dependent on the shipper volumes that commit to the project. The Enogex capacity will be a part of the proposed Midcontinent Express Pipeline (MEP), a joint venture between Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. In addition to the Enogex leased capacity, the proposed MEP project includes a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Pending necessary regulatory approval, the MEP pipeline project is currently expected to be in service by February 2009. Depending on the final capacity that MEP subscribes to pursuant to the agreement, Enogex expects its revenues from this firm capacity lease agreement to be between $12 million and $30 million annually. Enogex currently estimates that its capital expenditures related to this project during the next two to three years could be approximately $100 million. The Enogex lease agreement with MEP is subject to certain contingencies including regulatory approval. Prior to such approval, Enogex may incur expenditures of between approximately $20 million and $40 million with the majority being for certain commitments for materials that can be sold or used in normal operations in the event the MEP project does not proceed and the amount not recovered or utilized for such expenditures is not expected to be material. Enogex also is seeking to provide lease capacity to Boardwalk s Gulf Crossings project. Boardwalk Pipeline Partners, LP, has announced plans to build the Gulf Crossings pipeline, which includes 355 miles of new interstate natural gas pipeline. It initially is expected to transport gas from the supply areas in Sherman, Texas, Bennington, Oklahoma, and Paris, Texas to the Perryville, Louisiana Hub. Subject to regulatory approvals, the Gulf Crossings project is expected to be in service during the fourth quarter of 2008.

The Company s business strategy is to continue maintaining the diversified asset position of OG&E and Enogex so as to provide competitive energy products and services to customers primarily in the south central United States. The

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Company will continue to focus on those products and services with limited or manageable commodity exposure. In addition to the incremental growth opportunities that Enogex provides, the Company believes that many of the risk management practices, commercial skills and market information available from Enogex provide value to all of the Company s businesses. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Executive Overview for a further discussion.

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 269 communities and their contiguous rural and suburban areas. During 2006, five other communities and two rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from OG&E for resale. The service area, with an estimated population of 2.0 million, covers approximately 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 269 communities that OG&E serves, 243 are located in Oklahoma and 26 in Arkansas. OG&E derived approximately 89 percent of its total electric operating revenues for the year ended December 31, 2006 from sales in Oklahoma and the remainder from sales in Arkansas.

OG&E s system control area peak demand as reported by the system dispatcher during 2006 was approximately 6,473 MW s on August 10, 2006. OG&E s load responsibility peak demand was approximately 6,033 MW s on August 10, 2006. As reflected in the table below and in the operating statistics on page 5, there were approximately 26.4 million megawatt-hour (MWH) sales to OG&E s customers (system sales) in 2006 as compared to approximately 26.0 million in 2005 and 24.7 million in 2004. System sales increased approximately 1.5 percent in 2006 primarily due to warmer weather during 2006. Variations in system sales for the three years are reflected in the following table:

Year ended December 31 *(In millions)*	**2006**	**Increase**	2005	Increase	2004	Decrease
System Sales (A)	**26.4**	**1.5%**	26.0	5.3%	24.7	(1.2)%

(A) Sales are in millions of MWH s.

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. In a citywide election in May 2006, Oklahoma City voters approved a 25-year franchise for OG&E, which as noted above is the largest city in OG&E s service territory.

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. See Note 18 of Notes to Consolidated Financial Statements for a discussion of the potential impact on competition from federal and state legislation.

OKLAHOMA GAS AND ELECTRIC COMPANY
CERTAIN OPERATING STATISTICS

Year ended December 31 *(In millions)*		**2006**		2005		2004
ELECTRIC ENERGY *(Millions of MWH)*						
Generation (exclusive of station use)		**24.6**		24.8		22.6
Purchased		**3.9**		3.3		4.2
Total generated and purchased		**28.5**		28.1		26.8
Company use, free service and losses		**(2.1)**		(2.0)		(2.0)
Electric energy sold		**26.4**		26.1		24.8
ELECTRIC ENERGY SOLD *(Millions of MWH)*						
Residential		**8.7**		8.5		7.9
Commercial		**6.2**		6.0		5.7
Industrial		**7.1**		7.2		7.0
Public authorities		**2.9**		2.8		2.7
Sales for resale		**1.5**		1.5		1.4
System sales		**26.4**		26.0		24.7
Off-system sales		**---**		0.1		0.1
Total sales		**26.4**		26.1		24.8
ELECTRIC OPERATING REVENUES *(In millions)*						
Residential	**$**	**698.8**	$	663.6	$	611.4
Commercial		**428.3**		418.9		389.9
Industrial		**345.0**		355.6		326.7
Public authorities		**171.0**		173.1		158.5
Sales for resale		**65.4**		67.7		57.0
Provision for rate refund		**(0.9)**		(2.0)		(6.9)
System sales revenues		**1,707.6**		1,676.9		1,536.6
Off-system sales revenues		**2.7**		4.9		0.8
Other		**35.4**		38.9		40.7
Total Electric Operating Revenues	**$**	**1,745.7**	$	1,720.7	$	1,578.1
ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)*						
Residential		**647,548**		639,733		630,736
Commercial		**82,974**		81,728		80,786
Industrial		**9,505**		9,472		9,420
Public authorities		**14,769**		14,515		14,022
Sales for resale		**44**		45		44
Total		**754,840**		745,493		735,008
AVERAGE RESIDENTIAL CUSTOMER SALES						
Average annual revenue	**$**	**1,084.31**	$	1,043.60	$	975.08
Average annual use (kilowatt-hour (KWH))		**13,526**		13,455		12,630
Average price per KWH (cents)	**$**	**8.02**	$	7.76	$	7.72

Regulation and Rates

OG&E s retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E s wholesale electric tariffs, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the Department of Energy has jurisdiction over some of OG&E s facilities and operations. For the year ended December 31, 2006, approximately 87 percent of OG&E s electric revenue was subject to the jurisdiction of the OCC, nine percent to the APSC and four percent to the FERC.

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

OG&E has been and will continue to be affected by competitive changes to the utility industry. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although it appears unlikely in the near future that changes will occur to retail regulation in the states served by OG&E due to the significant problems faced by other states in their electric deregulation efforts and other factors, significant changes are possible, which could significantly change the manner in which OG&E conducts its business. These developments at the federal and state levels are described in more detail in Note 18 of Notes to Consolidated Financial Statements.

Recent Regulatory Matters

OG&E Wind Power Filing. On February 20, 2006, OG&E entered into an agreement to engineer, procure and construct the 120 MW Centennial wind farm planned for construction in northwestern Oklahoma. The wind farm was fully in service in January 2007. Through December 31, 2006, OG&E has spent approximately $171.1 million related to the Centennial wind farm. On April 28, 2006, the OCC approved a settlement agreement approving the wind power contract and a recovery rider for up to $205 million in construction costs and allowance for funds used during construction. The settlement also indicated that OG&E shall file for a general rate review during 2009 that will permit the OCC to issue an order no later than December 31, 2009 placing the Centennial wind farm in OG&E s rate base. On January 17, 2007, OG&E sent notice to the OCC to trigger the Centennial wind farm rider for the first billing cycle in February 2007. The recovery rider is designed to recover approximately $22.6 million in the first year of operations, which amount will decline over the life of the facility. Because the wind farm rider was implemented in February 2007, OG&E expects to recover approximately $20.7 million under the rider during the remaining 11 months of 2007. OG&E expects the recovery rider to remain in effect through late 2009. As explained below, the recent rate order from the APSC allows for the recovery of the portion of the Centennial wind farm allocable to OG&E s customers in Arkansas.

OG&E Arkansas Rate Case Filing. On July 28, 2006, OG&E filed with the APSC an application for an annual rate increase of approximately $13.5 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant, the Centennial wind power project and the costs of electric system expansion and upgrades based on a return on equity of 11.75 percent. On November 29, 2006, OG&E reached a settlement with the other parties in this case for an annual rate increase of approximately $5.4 million. In the settlement agreement, the parties also agreed that OG&E would be allowed to recover the full Arkansas portion of the Centennial wind farm. On January 5, 2007, the APSC approved the settlement and issued a rate order that provides for a $5.4 million annual increase in OG&E s electric rates and a 10.0 percent return on equity. The new Arkansas rates became effective in February 2007.

Proposed Construction of Power Plant. On July 18, 2006, the Company announced plans for OG&E to partner with American Electric Power s subsidiary, Public Service Company of Oklahoma (PSO), and the Oklahoma Municipal Power Authority (OMPA) to build a new 950 MW coal unit at OG&E s existing Sooner plant location near Red Rock, Oklahoma. The estimated $1.8 billion project is the result of PSO s December 2005 request for proposals in which it sought bids for up to 600 MW s of new base load generation to be available to PSO. The unit, to be called Red Rock, is expected to be one of the cleanest of its size using coal from the Powder River Basin, which is located near Gillette, Wyoming. OG&E will operate the facility and expects to spend approximately $759 million in construction costs related to its 42 percent ownership percentage in the project and approximately $30 million in transmission costs for the project. PSO will own 50 percent and the OMPA will own eight percent. On December 1, 2006, OG&E submitted an application to the Oklahoma

Department of Environmental Quality (ODEQ) for an air permit for the Red Rock plant. OG&E is seeking to have the air permit approved by the ODEQ by August 1, 2007. OG&E expects construction to begin in 2007 and is targeting the completion of the power plant in the 2011/2012 timeframe. OG&E filed an application with the OCC on January 17, 2007 asking the OCC to find that its portion of the construction costs are prudent and that a recovery mechanism should be established to recover OG&E s overall cost of capital on the investment during the construction period. The OCC rules provide that the OCC has up to 240 days to issue an order determining OG&E s pre-approval request, however OG&E s application requested that the OCC issue an order by July 20, 2007. The project is contingent upon numerous factors, including the successful completion of contract negotiations and the necessary regulatory and environmental approvals. Under the construction, ownership and operating agreement between OG&E, PSO and the OMPA, the parties could incur up to $60 million (of which approximately $25 million would be borne by OG&E) prior to the receipt of acceptable regulatory approvals and permits. If such approvals and permits were not obtained and the Red Rock project was abandoned, the Company can provide no assurance that these expenditures incurred by OG&E would be recoverable in future rates.

See Note 18 of Notes to Consolidated Financial Statements for a discussion of certain regulatory matters including, among other things, the gas transportation and storage contract between OG&E and Enogex, OG&E s 2005 Oklahoma rate case order, security enhancements, national energy legislation and state legislative initiatives.

Regulatory Assets and Liabilities

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

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

At December 31, 2006 and 2005, OG&E had regulatory assets of approximately $319.2 million and $189.2 million, respectively, and regulatory liabilities of approximately $224.5 million and $118.1 million, respectively. See Note 1 of Notes to Consolidated Financial Statements for a further discussion.

As discussed in Note 18 of Notes to Consolidated Financial Statements, legislation was enacted in Oklahoma that was to restructure the electric utility industry in that state. The implementation of the Oklahoma restructuring legislation has been delayed and seems unlikely to proceed during the near future. Yet, if and when implemented, this legislation could deregulate OG&E s electric generation assets and cause OG&E to discontinue the use of SFAS No. 71 with respect to its related regulatory balances. The previously-enacted Oklahoma legislation would not affect OG&E s electric transmission and distribution assets and OG&E believes that the continued use of SFAS No. 71 with respect to the related regulatory balances is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management believes that its regulatory assets, including those related to generation, are probable of future recovery.

Rate Structures

Oklahoma

OG&E has had several different customer programs and rate options. The Guaranteed Flat Bill (GFB) option for residential and small general service accounts allows qualifying customers the opportunity to purchase their electricity needs at a set price for an entire year. Budget-minded customers that desire a fixed monthly bill may benefit from the GFB option. The GFB option received OCC approval for permanent rate status in OG&E s rate case completed in December 2005. A second tariff rate option provides a renewable energy resource to OG&E s Oklahoma retail customers. This renewable energy resource is a wind power 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 wind power option a possible choice in meeting the renewable energy needs of our conservation-minded customers and provides the customers with a means to reduce their exposure to increased prices for natural gas used by OG&E as boiler fuel. A third rate offering available to commercial and industrial customers is levelized demand billing. This program is beneficial for medium to large size customers with seasonally consistent demand levels who wish to reduce the variability of their monthly electric bills.

Another program being offered to OG&E s commercial and industrial customers is a voluntary load curtailment program. This program provides customers with the opportunity to curtail 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.

The previously discussed rate options coupled with OG&E s other rate choices provide many tariff options for OG&E s Oklahoma retail customers. 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 our customers for many years to come. The revenue impacts associated with these options are indeterminate in future years since customers may choose to remain on existing rate options instead of volunteering for the new rate option choices. There was no overall material impact in 2005 or 2006 associated with these rate options, but revenue variations may occur in the future based upon changes in customers usage characteristics if they choose these programs.

As part of the rate order issued by the OCC in December 2005, OG&E received OCC approval for the creation of two new rate classes, Public Schools-Demand and Public Schools Non-Demand. These two classes of service will provide OG&E flexibility to provide targeted programs for load management to public schools and their unique usage patterns. Another item approved in the order was the creation of service level fuel differentiation that allows customers to pay fuel costs that better reflect operational energy losses related to a specific service level. The OCC order also approved a military base rider that demonstrates Oklahoma s continued commitment to our military partners.

Arkansas

Energy efficiency hearings are also currently being held by the APSC for all Arkansas utilities. These hearings are expected to lead to various conservation options and programs in the near future and result in better use of energy resources.

Fuel Supply

During 2006, approximately 67 percent of the OG&E-generated energy was produced by coal-fired units and 33 percent by natural gas-fired units. Of OG&E s 6,079 total MW capability reflected in the table under Item 2. Properties, approximately 3,480 MW s, or 57 percent, are from natural gas generation and approximately 2,599 MW s, or 43 percent, are from coal 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. A slight decline in the percentage of coal generation in future years is expected to result from increased usage of natural gas generation required to meet growing energy needs. Over the last five years, the weighted average cost of fuel used, by type, per million British thermal unit (MMBtu) was as follows:

Year ended December 31	**2006**	2005	2004	2003	2002
Coal	**$ 1.10**	$ 0.98	$ 1.00	$ 0.93	$ 0.93
Natural Gas	**$ 7.10**	$ 8.76	$ 6.57	$ 6.46	$ 3.78
Weighted Average	**$ 2.98**	$ 3.21	$ 2.69	$ 2.27	$ 1.77

The decrease in the weighted average cost of fuel in 2006 as compared to 2005 was primarily due to decreased natural gas prices partially offset by increased amounts of natural gas being burned. The increase in the weighted average cost of fuel in 2005 and in 2004 was primarily due to increased natural gas prices and increased amounts of natural gas being burned. The increase in the weighted average cost of fuel in 2003 as compared to 2002 was primarily due to increased natural gas prices in 2003 partially offset by a lower amount of natural gas burned in 2003. A portion of these fuel costs is included in the base rates to customers and differs for each jurisdiction. The portion of these fuel costs that is not included in the base rates is recoverable through OG&E s regulatorily approved automatic fuel adjustment clauses.

Coal

All of OG&E s coal-fired units, with an aggregate capability of approximately 2,599 MW s, are designed to burn low sulfur western coal. OG&E purchases coal primarily under long-term contracts expiring in years 2010 and 2011. During 2006, OG&E purchased approximately 10.1 million tons of coal from various Wyoming suppliers. The combination of all coal has a weighted average sulfur content of less than 0.3 percent and can be burned in these units under existing federal, state and local environmental standards (maximum of 1.20 lbs. of sulfur dioxide per MMBtu) without the addition of sulfur dioxide removal systems. Based upon the average sulfur content, OG&E s coal units have an approximate emission rate of

0.52 lbs. of sulfur dioxide per MMBtu, well within the limitations of the current provisions of the Federal Clean Air Act discussed in Note 17 of Notes to Consolidated Financial Statements.

OG&E has continued its efforts to maximize the utilization of its coal-fired units at its Sooner and Muskogee generating plants. See Environmental Laws and Regulations in Note 17 of Notes to Consolidated Financial Statements for a discussion of environmental matters which may affect OG&E in the future.

Coal Shipment Disruption

In July 2005, OG&E received notification from Union Pacific Railroad (Union Pacific) that, in May 2005, Union Pacific and BNSF Railway (BNSF) experienced successive derailments on the jointly-owned rail line serving the Southern Powder River Basin coal producers. According to Union Pacific, these two derailments were caused by track that had become unstable from an accumulation of coal dust in the roadbed combined with unusually heavy rainfall. BNSF, which maintains and operates the line, concluded that a significant part of the line needed to be repaired before normal train operations could resume. While the repairs were taking place, Union Pacific was unable to operate at full capacity from the Powder River Basin. In November 2005, Union Pacific notified OG&E that the South Powder River Basin joint line force majeure condition that was declared in May 2005 had ended. On December 2, 2005, BNSF completed the enhanced joint line maintenance program which opened the way for a return to normal operating conditions. It is expected that as rail traffic improves, OG&E will be able to increase its level of coal inventories. At December 31, 2006, OG&E had slightly more than 30 days of coal supply for each of its coal-fired units at its Sooner and Muskogee generating plants. Furthermore, if no other significant disruptions occur going forward, OG&E now expects to replenish its coal inventory to pre-disruption levels by the end of 2008.

Natural Gas

In October 2006, OG&E issued and completed a request for proposal (RFP) for gas supply purchases for periods that began in November 2006 through March 2007, which accounted for approximately eight percent of its projected 2007 natural gas requirements. All of these contracts are tied to various gas price market indices and will expire in 2007. OG&E s remaining 2007 natural gas requirements will be met with additional RFP s issued in early to mid-2007. OG&E will meet additional natural gas requirements with monthly and daily purchases as required.

In 1993, OG&E began utilizing a natural gas storage facility for storage services that allowed OG&E to maximize the value of its generation assets. Storage services are now provided by Enogex as part of Enogex s gas transportation and storage contract with OG&E. At December 31, 2006, OG&E had approximately 1.6 million MMBtu s in natural gas storage that it acquired for approximately $5.9 million.

Purchased Power

In October 2006, OG&E issued an RFP for firm economy energy purchases during the summer of 2007 and expects to select a supplier in early 2007. Also, in early 2007, OG&E expects to issue an RFP for capacity and/or firm energy purchases for the summer periods of 2008 through 2010 and expects to select a supplier by the early summer of 2007.

NATURAL GAS PIPELINE OPERATIONS - ENOGEX

Overview

The operations of the Natural Gas Pipeline segment are conducted through Enogex and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. Enogex s focus is to utilize its gathering, processing, transportation and storage capacity to execute physical, financial and service transactions to capture margins across different natural gas related commodities, locations or time periods. The vast majority of Enogex s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Enogex and its subsidiaries operate approximately 7,757 miles of intrastate natural gas gathering and transportation pipelines.

Strategy

The transportation, storage and gathering assets of Enogex provide OG&E with strategic access to natural gas supplies, and flexible and reliable delivery terms that are required to fuel OG&E s natural gas-fired generation facilities. Natural gas generation peaking units require the ability to quickly change their status, to meet both the peak and off-peak demands of the retail load particularly when coal units have an unscheduled outage. The gathering assets access major wellhead supply sources primarily located across Oklahoma, and the integrated transportation and storage assets provide the ability to regulate the receipt and delivery of natural gas to match the instantaneous needs of these generation units.

Natural gas-fired generation units contribute their highest value when they have the capability to provide load following service to the customer (i.e., the ability of the generation unit to regulate generation to respond to and meet the instantaneous changes in customer demand). While the physical characteristics of natural gas units are known to provide quick start-up and on-line functionality, and while their ability to efficiently provide varying levels of electric generation relative to other forms of generation is further acknowledged, their ultimate effectiveness is contingent upon having access to an integrated pipeline and storage system that can respond in a short term fashion to meet the corresponding fluctuating operational fuel requirements. The combination of these assets is critical to a generator s ability to provide reliable generation service at reasonable prices to the consumer.

Not only is Enogex providing firm gas transportation service to OG&E, but Enogex s same assets provide firm and interruptible services to a significant portion of the other natural gas-fired generation loads in Oklahoma. Enogex understands the needs of generators, and more importantly has the appropriately-sized pipelines, compression and integrated storage assets necessary to meet their requirements.

Through Enogex s gathering and processing assets, Enogex aggregates gas supplies for its markets and also for those markets accessible via its numerous intrastate and interstate pipeline connections. It aggressively pursues new supplies from wells drilled by producers primarily in the Arkoma and Anadarko basins (including recent growth activity in western Oklahoma, the Texas Panhandle and in the Woodford Shale developments in southeastern Oklahoma). Oklahoma ranks second in the nation in onshore natural gas production and ranks third in the nation as a natural gas exporting state. Enogex s system capacity, due to its large diameter gathering pipelines and its natural gas processing plants, is capable of adapting to the varying pressure and quality requirements of mid-continent production. Enogex is able to provide low-pressure service to extend the production life of older wells and to provide high-pressure service to meet the requirements of new exploration. Through its processing plants, Enogex also is able to remove natural gas liquids from the wellhead gas streams, which is necessary for such gas to meet quality specifications of the downstream marketplace.

Besides the core activities described above, the transportation capabilities and markets of Enogex s pipeline assets provide other business opportunities. These include the ability of Enogex to use its pipeline system and storage assets as a market hub . At December 31, 2006, Enogex was connected to 13 other major pipelines at approximately 64 pipeline interconnect points providing access to markets in the western United States, the Midwest, Northeast, and Gulf Coast in addition to Oklahoma and adjoining states. As a result, Enogex s assets sit in a key geographic region of the United States, with sufficient capacity to provide crosshaul transportation and storage services to a variety of utility and industrial customers that need to access mid-continent natural gas supply for their own needs, or to suppliers from other regions seeking to provide gas to on-system markets which Enogex serves.

Enogex s marketing business provides products and services that support the market hub concept and are an important element in the Company realizing the full value of its transportation and storage assets. The marketing business offers the Company real-time and longer-term price discovery and valuation of energy commodities (natural gas and associated natural gas liquids) associated with the Company s assets. The marketing business is instrumental in providing increased liquidity for these energy commodities by focusing on developing supplies and markets that can access the Enogex systems either directly or via interconnections with intrastate and interstate pipelines. The marketing business also provides the Company the capability to provide risk management services to the Company and to its customers.

The Company intends to continue to build upon the foundation of services and products that these natural gas assets can provide. In addition, the Company expects to generate additional margins by improving its ability to aggregate gas, maximize the operational capabilities of its assets and utilize commercial information available from the marketplace.

On December 15, 2006, Enogex announced that it had entered into firm capacity lease agreement with Midcontinent Express Pipeline, LLC for a primary term of 10 years (subject to possible extensions) for certain capacity on the Enogex system. The leased capacity provided for in this agreement is up to 0.5 Bcf per day and is dependent on the shipper volumes that commit to the project. The Enogex capacity will capacity be a part of the proposed MEP, a joint venture between Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. In addition to the Enogex leased capacity, the proposed MEP project includes a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Pending necessary regulatory approval, the MEP pipeline project is currently expected to be in service by February 2009. Depending on the final capacity that MEP subscribes to pursuant to the agreement, Enogex expects its revenues from this firm capacity lease agreement to be between $12 million and $30 million annually. Enogex currently estimates that its capital expenditures related to this project during the next two to three years could be approximately $100 million. The Enogex lease agreement with MEP is subject to certain contingencies including regulatory approval. Prior to such approval, Enogex may incur expenditures of between approximately $20 million and $40 million with the majority being for certain commitments for materials that can be sold or used in normal operations in the event the MEP project does not proceed and the amount not recovered or utilized for such expenditures is not expected to be material. Enogex also is seeking to provide lease capacity to Boardwalk s Gulf Crossings project. Boardwalk Pipeline Partners, LP, has announced plans to build the Gulf Crossings pipeline, which includes 355 miles of new interstate natural gas pipeline. It initially is expected to transport gas from the supply areas in Sherman, Texas, Bennington, Oklahoma and Paris, Texas to the Perryville, Louisiana Hub. Subject to regulatory approvals, the Gulf Crossings project is expected to be in service during the fourth quarter of 2008.

Enogex had previously announced that it had entered into a letter of intent with El Paso Corporation (El Paso) relating to El Paso s Continental Connector Project. The letter of intent contemplated arrangements by which El Paso or an affiliate would execute a lease of capacity on the Enogex pipeline system and the leased Enogex pipeline capacity would become part of the Continental Connector Project. The letter of intent expired on April 28, 2006. In early October 2006, El Paso determined not to proceed with its proposed Continental Connector project. Enogex did not incur any material expenditures relating to this proposed project.

Dispositions

Transportation and Storage. During September 2004, Enogex received notification from a customer that a transportation agreement involving four of Enogex s non-contiguous pipeline asset segments located in West Texas and used to serve the customer s power plants would be terminated effective December 31, 2004. In response to this notification, the Company recognized, during the third quarter of 2004, a pre-tax impairment loss of approximately $8.6 million in the Natural Gas Pipeline segment related to Enogex natural gas pipeline assets that were used to provide service to this customer. In December 2004, the Company received notification that all of this customers plants in West Texas were shut down and service was no longer required. In November 2006, Enogex sold the four non-contiguous pipeline asset segments for approximately $1.0 million. Enogex recognized a pre-tax gain of approximately $1.0 million in the fourth quarter of 2006 related to the sale of these assets.

Enogex regularly evaluates the long term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on these evaluations, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in EAPC, which held its NOARK interest. This sale was completed on October 31, 2005. The Company received approximately $177.4 million in cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter of 2005. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million, was used, among other things, to reduce short-term debt levels and fund capital expenditures.

In March 2006, Enogex announced that its wholly-owned subsidiary, Gathering, had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction were approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and Enogex recorded an after tax gain of approximately $34.1 million during the second quarter of 2006. The proceeds from the sale, were used, among other things, to reduce short-term debt levels and fund capital expenditures.

Capital Expenditures; Improvement Projects.

As discussed above, in August 2006, Enogex completed a project to expand its gathering pipeline capacity on the west side of its system in western Oklahoma and the Texas Panhandle that should enable Enogex to benefit from growth opportunities in that marketplace. Enogex continues to consider additional opportunities to expand this project.

In 2005, Enogex completed a major upgrade of its information systems that began in 2003. Enogex believes that these upgrades have been a major step towards obtaining the data required to allow it to capture available economic opportunities on its assets, provide improved customer service and enable management to better determine the earnings potential of its various assets and service offerings. One information system implemented provided a single system for pipeline equipment control, data collection, management and measurement of gas volumes and pressures, which has improved Enogex s access to critical data for daily system management decisions. Another information system implemented, together with the Company s primary enterprise-wide general ledger software, has been used to accumulate

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and analyze financial data used in financial reporting. This change in information systems was made to eliminate previous stand alone systems and integrate them into one system. Also, the Company is investing in upgrades and enhancements to continue to improve the functionality of its information systems.

On a company-wide basis, the Company implemented an enhanced digital asset mapping technology for both OG&E and Enogex in May 2006. The new system supports a significant increase in the number of our members who use this technology in their jobs, expanding the productive use of geographic asset information in a variety of ways, including daily operations, maintenance, budgeting, planning, purchasing and accounting. Also, Enogex began work on a flow data access project called ProductionWatch at the end of the second quarter of 2005. Initial phases of implementation were completed by June 2006 with the final phases of implementation of this project being completed by the end of 2007. ProductionWatch is a service that provides data (volume, pressure, temperature, etc.) from the Enogex meter to Enogex s customers for a fee. ProductionWatch data will be available to customers via the internet and it may also be downloaded by customers from Enogex network servers. Such data is attractive because it enables Enogex customers to increase gas production and reduce operating costs. From Enogex s perspective, ProductionWatch provides Enogex with an additional revenue stream while helping Enogex operate more efficiently.

Transportation and Storage

General. One of Enogex s primary lines of business is the transportation of natural gas, with current throughput of approximately 1.4 trillion British thermal units (Btu) per day. Enogex delivers natural gas to most interstate and intrastate pipelines and end-users connected to its systems from the Arkoma and Anadarko basins (including recent growth activity in western Oklahoma, the Texas Panhandle and in the Woodford Shale developments in southeastern Oklahoma). At December 31, 2006, Enogex was connected to 13 other major pipelines at approximately 64 pipeline interconnect points. These interconnections include Panhandle Eastern Pipe Line, Southern Star Central Gas Pipeline (formerly Williams Central), Natural Gas Pipeline Company of America, Oneok Gas Transmission, Northern Natural Gas Company, ANR Pipeline, Western Farmers Electric Cooperative, CenterPoint Energy Gas Transmission Co., El Paso Natural Gas Pipeline, Enbridge Pipelines, Oneok WesTex Transmission L.P. and Ozark Gas Transmission, L.L.C. Further, Enogex is connected to various end-users including numerous electric generation facilities in Oklahoma that are fueled by natural gas. At December 31, 2006, the net property, plant and equipment balance for Enogex s transportation and storage business was approximately $514.0 million.

Enogex owns two storage facilities in Oklahoma, the Wetumka Storage Facility and the Stuart Storage Facility. These storage facilities are currently being operated at a working gas level of approximately 23 Bcf with an approximate withdrawal capability of 650 million cubic feet per day (MMcfd) and similar injection capability. Enogex offers both firm and interruptible storage services to third parties, under Section 311 of the Natural Gas Policy Act (NGPA), under terms and conditions specified in its Statement of Operating Conditions (SOC) for gas storage and at market-based rates negotiated with each customer. Both facilities also are used to support Enogex s intrastate transportation and storage services for OG&E.

Enogex offers firm intrastate transportation services and derives the majority of its transportation revenues from these services. To the extent pipeline capacity is not needed for such firm intrastate service, Enogex offers interruptible interstate transportation services pursuant to Section 311 of the NGPA as well as interruptible intrastate transportation services.

Enogex provides firm intrastate transportation and storage services to several customers on its system. Enogex s major customers are OG&E as well as PSO, the second largest electric utility in Oklahoma, serving the Tulsa market. Enogex provides gas transmission delivery services to all of PSO s natural gas-fired electric generation units in Oklahoma under a firm intrastate transportation contract. The PSO contract, which expires January 1, 2013, and the OG&E contract, which expires April 30, 2009, provide for a monthly demand charge plus variable transportation charges (including fuel). As part of the 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 Enogex acquired the Stuart Storage Facility from Central Oklahoma Oil and Gas Corp. During 2006, 2005 and 2004, Enogex s revenues from its firm intrastate transportation and storage contracts were approximately $98.1 million, $95.0 million and $95.6 million, respectively.

Relationship with OG&E. From its inception, Enogex has been the transporter of natural gas to OG&E s natural gas-fired generation facilities. OG&E s rates are subject to OCC jurisdiction. Following a consideration of competitive bidding by OG&E as required by a prior order from the OCC, OG&E s contract with Enogex was amended by an agreement dated May 1, 2003 with no-notice load following requirements and a termination date of April 30, 2009. The amount collected from OG&E by Enogex under the current contract for transportation services was approximately $34.9 million,

$34.9 million and $34.3 million, respectively, during 2006, 2005 and 2004. This amount collected from OG&E by Enogex under the current contract for storage services was approximately $12.7 million, $12.7 million and $15.3 million, respectively, during 2006, 2005 and 2004. In July 2005, OG&E received an OCC order related to its application to recover the costs of gas transportation and storage services provided to OG&E by Enogex pursuant to the contract between OG&E and Enogex. See Note 18 of Notes to Consolidated Financial Statements for a further discussion of this matter.

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

Regulation. The rates charged by Enogex for transporting natural gas on behalf of an interstate natural gas pipeline company or a local distribution company served by an interstate natural gas pipeline company are subject to the jurisdiction of the FERC under Section 311 of the NGPA. Rates to provide such service must be fair and equitable under the NGPA and are subject to review and approval by the FERC at least once every three years. This rate review may, but will not necessarily, involve an administrative-type hearing before the FERC Staff panel and an administrative appellate review. Offering interruptible Section 311 transportation gives Enogex the opportunity to utilize any unused capacity on an interruptible basis in interstate commerce and thus increase its transportation revenues without increasing its regulatory burden appreciably. Beginning January 1, 2006, Enogex s approved Section 311 rate structure includes a provision for Enogex to charge a fixed fuel percentage, by zone, for the fuel usage for natural gas shipped on its system. The fixed zonal fuel percentages are adjusted annually and remain in effect for a calendar fuel year (unless Enogex files with the FERC to adjust the zonal percentages more frequently). The mechanism used to recover such fuel is a fuel tracker that establishes the zonal fixed fuel factors (expressed as a percentage of natural gas shipped in the zone) that is trued-up over a two year period and based on the value of the gas at the time of usage. Prior to January 1, 2006, Enogex recovered a system-wide fixed fuel percentage as opposed to the current zonal fixed fuel percentages.

On September 1, 2004, Enogex made a filing at the FERC to revise its previously approved SOC to permit, among other things, the unbundling, effective October 1, 2004, of its previously bundled gathering and transportation services. As a result, effective October 1, 2004, the FERC regulates Enogex s Section 311 transportation but does not regulate Enogex s gathering.

On September 30, 2004, Enogex made its required triennial filing at the FERC to update its Section 311 maximum interruptible transportation rate. On September 29, 2004, Enogex filed an updated fuel factor with the FERC for the last quarter of 2004. Finally, on November 15, 2004, Enogex filed its annual updated system-wide fuel factor for fuel year 2005 (calendar year 2005). The proceedings were resolved by a unanimous settlement that the FERC approved without modification or condition, by order of September 19, 2005. The Settlement established new maximum interruptible Section 311 zonal rates for an East Zone and a West Zone on the Enogex system, confirmed that Enogex could unbundle its gathering and transportation services and permitted the fuel factor percentages for the last quarter of 2004 and for fuel year 2005 to become effective, as filed. The FERC order concluded all four proceedings which resulted in no refunds being due. Enogex must file its next rate case no later than October 1, 2007 to comply with the FERC s requirement for triennial filings.

As required by the fuel tracker provisions of its SOC, Enogex files annually to update its fuel percentages. On November 15, 2006, Enogex filed zonal fuel percentages for the 2007 calendar fuel year. As had been agreed in the settlement of the 2004 Section 311 rate case, Enogex established an East Zone fixed fuel percentage and a West Zone fixed fuel percentage to be recalculated annually to replace the system-wide fixed fuel percentage previously established annually for the Enogex system. By order dated December 19, 2006, the FERC approved and accepted Enogex s November 15, 2006 zonal fuel factors as fair and equitable effective January 1, 2007.

The rates charged by Enogex for transporting natural gas for OG&E and other shippers within Oklahoma are not subject to FERC regulation because they are intrastate transactions. The rates charged by Enogex for any intrastate transportation service is not subject to direct state regulation by the OCC. The OCC, the APSC and the FERC (all of which approve various electric rates of OG&E) have the authority to examine the appropriateness of any transportation charges or other fees paid by OG&E to Enogex which OG&E seeks to recover from its ratepayers in its cost-of-service for electric service. See Note 18 of Notes to Consolidated Financial Statements for a discussion of the OCC order OG&E received in July 2005 related to the amounts charged OG&E by Enogex for gas transportation and storage services.

Enogex s pipeline operations are subject to various Oklahoma safety and environmental and pipeline transportation laws.

Gathering and Processing

General. Natural gas gathering operations are conducted through Gathering and natural gas processing operations are conducted through Enogex Products Corporation (Products). The streams of processable natural gas gathered from wells and other sources are gathered through Enogex s gas gathering systems and delivered to processing plants for the extraction of natural gas liquids. During 2006, Gathering connected 206 new producing wells, located in the Arkoma and Anadarko basins (including recent growth activity in western Oklahoma, the Texas Panhandle and in the Woodford Shale developments in southeastern Oklahoma), to its gathering systems. The Company provides connection, measurement, treating, dehydration and compression services for various types of producing wells owned by various sized producers who are active in the region. Where the quality of natural gas received dictates that removal of natural gas liquids may be in order, such gas is aggregated via the gathering system to the inlet of one or more of the Company s fleet of processing plants owned and operated by Products. The resulting processed stream of natural gas is then delivered via the Enogex pipeline system to one or more delivery points into the web of transmission pipelines in the region. Products is one of the largest gas processors in Oklahoma, operating six natural gas processing plants with a total inlet capacity of 723 MMcfd. Products has been active since 1968 in the processing of natural gas and extraction and marketing of natural gas liquids. The liquids extracted include condensate, marketable ethane, propane, butanes and natural gasoline mix. The residue gas remaining after the liquid products have been extracted consists primarily of ethane and methane. In 2006, approximately 371 million gallons of natural gas liquids were sold. At December 31, 2006, the net property, plant and equipment balance for Enogex s gathering and processing business was approximately $351.2 million.

Approximately 19 percent of the commercial grade propane produced at Products plants is sold on the local market. The balance of propane and the other natural gas liquids produced by Products is delivered into pipeline facilities of a third party and transported to Conway, Kansas and Mont Belvieu, Texas, where they are sold under contract or on the spot market. Ethane, which may be optionally produced at all of Products plants except one, is sold under contract or on the spot market.

Competition. 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. In processing and marketing natural gas liquids, Products competes against virtually all other gas processors extracting and selling natural gas liquids in its market area. Competition for natural gas supply is based on efficiency and reliability of operations, reputation, proximity to existing assets, access to markets and pricing. Enogex believes it will be able to continue to compete effectively.

With respect to the profitability of the natural gas processing industry, generally if the price of natural gas liquids falls without a corresponding decrease in the cost of natural gas, it may become uneconomical to extract certain natural gas liquids. This factor has had a significant adverse impact on the results of Enogex in the past, but, as discussed above, the potential adverse impact has been materially mitigated, but not entirely eliminated. In addition to the commodity pricing impact that affects the entire industry, the profitability of Products is also largely affected by the volume of natural gas processed at its plants which is highly dependent upon the volume and Btu content of natural gas gathered. Generally, if the volume of natural gas gathered increases, then the volume of natural gas liquids extracted by Products should also increase.

Marketing

General. Enogex s commodity sales and services related to natural gas are conducted primarily through its subsidiary, OGE Energy Resources, Inc. (OERI). OERI is engaged in the business of natural gas marketing. OERI provides marketing services to Enogex for natural gas volumes purchased at the wellhead from customers. As a service to the producers on the Enogex system, Enogex may agree to purchase the gas at the wellhead in conjunction with gathering their gas for transportation to other markets. OERI also purchases and sells natural gas pursuant to contracts with Enogex and Products relating to Enogex s gathering, processing and storage assets.

OERI focuses on serving customers along the natural gas value chain, from producers to end-users, by purchasing natural gas from suppliers and reselling to pipelines, local distribution companies and end-users, including the electric generation sector. The geographic scope of marketing efforts has been focused largely in the mid-continent area of the United States. These markets are natural extensions of OERI s business on the Enogex system. OERI contracts for pipeline capacity with Enogex and other pipelines to access multiple interconnections with the interstate pipeline system network that moves natural gas from the production basins primarily in the south central United States to the major consumption areas in Chicago, New York and other north central and mid-Atlantic regions of the United States. In 2005, OERI implemented a refocused strategy that seeks to minimize the amount of capital employed and to complement better the natural gas pipeline business. OERI has expanded into the Gulf Coast and Rocky Mountain markets to diversify its business and to facilitate Enogex s business development efforts.

OERI primarily participates in both intermediate-term markets (less than three years) and short-term spot markets for natural gas. Although OERI continues to increase its focus on intermediate-term sales, short-term sales of natural gas are expected to continue to play a critical role in the overall strategy because they provide an important source of market intelligence as well as an important portfolio balancing function. OERI s average daily sales volumes dropped from approximately 1.4 Bcf in 2005 to approximately 0.8 Bcf in 2006. This reflects selective deal execution to assure adequate margin in light of credit and other risks in the current high commodity price environment. OERI s risk management skills afford its customers the opportunity to tailor the risk profile and composition of their natural gas portfolio. The Company follows a policy of hedging price risk on gas purchases or sales contracts entered into by OERI by buying and selling natural gas futures contracts on the New York Mercantile Exchange futures exchange and other derivatives in the over-the-counter market, subject to daily and monthly trading stop loss limits of $2.5 million and daily value-at-risk limits of $1.5 million in accordance with corporate policies.

Competition. OERI competes in marketing natural gas with major integrated oil companies, marketing affiliates of major interstate and intrastate pipelines and commercial banks, national and local natural gas brokers, marketers and distributors for natural gas supplies. Competition for natural gas supplies is based primarily on reputation, credit support, the availability of gathering and transportation to high-demand markets and the ability to obtain a satisfactory price for the producer s natural gas. Competition for sales to customers is based primarily upon reliability, services offered and the price of delivered natural gas.

For the year ended December 31, 2006, approximately 54.4 percent of OERI s service volumes were with electric utilities, local gas distribution companies, pipelines and producers. The remaining 45.6 percent of service volumes were to marketers, municipals, cooperatives and industrials. At December 31, 2006, approximately 82.4 percent of the payment exposure was to companies having investment grade ratings with Standard & Poor s Ratings Services (Standard & Poor s) and approximately 1.2 percent having less than investment grade ratings. The remaining 16.4 percent of OERI s exposure is with privately held companies, municipals or cooperatives that were not rated by Standard & Poor s. OERI applies internal credit analyses and policies to these non-rated companies.

FINANCE AND CONSTRUCTION

Future Capital Requirements

Capital Requirements

The Company s primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and at Enogex. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage, delays in recovering unconditional fuel purchase obligations and fuel clause under and over recoveries. The Company generally meets its cash needs through a combination of internally generated funds, 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 Conditions and Results of Operations Liquidity and Capital Requirements for a discussion of the Company s capital requirements.

Capital Expenditures

The Company s current 2007 to 2012 construction program includes continued investment in OG&E s distribution, generation and transmission system and Enogex s pipeline assets. The Company s current estimates of capital expenditures for 2007 through 2012 are approximately $568.1 million, $838.6 million, $815.9 million, $659.9 million, $550.2 million and $436.0 million, respectively, which include capital expenditures of approximately $94.0 million, $278.8 million, $285.7 million, $97.7 million and $34.1 million, respectively, in 2007 through 2011 related to the construction of the proposed Red Rock power plant discussed below. OG&E also has approximately 550 MW s of contracts with qualified cogeneration facilities (QF) and small power production producers (QF contracts) to meet its current and future expected customer needs. OG&E will continue reviewing all of the supply alternatives to these QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates.

In July 2006, the Company announced plans for OG&E to partner with PSO and the OMPA to build a new 950 MW coal unit at OG&E s existing Sooner plant location near Red Rock, Oklahoma. The estimated $1.8 billion project is the result of PSO s December 2005 request for proposals in which it sought bids for up to 600 MW s of new base load generation to be available to PSO. The unit, to be called Red Rock, is expected to be one of the cleanest of its size using coal from the Powder River Basin, which is located near Gillette, Wyoming. OG&E will operate the facility and expects to spend approximately $759 million in construction costs related to its 42 percent ownership percentage in the project and approximately $30 million in transmission costs for the project. PSO will own 50 percent and the OMPA will own eight percent. For additional information regarding the proposed construction of this power plant, see Note 18 of Notes to Consolidated Financial Statements.

Pension and Postretirement Benefit Plans

During 2006 and 2005, the Company made contributions to its pension plan of approximately $90.0 million and $32.0 million, respectively, to ensure that the pension plan maintains an adequate funded status. During 2007, the Company may contribute up to $50 million to its pension plan. See Item 7. Management s Discussion and Analysis of Financial Conditions and Results of Operations Liquidity and Capital Requirements for a discussion of the Company s pension and postretirement benefit plans.

Future Sources of Financing

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

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. In December 2006, the Company and OG&E increased their aggregate available borrowing capacity under their revolving credit agreements from $750.0 million to $1.0 billion, $600 million for the Company and $400 million for OG&E. Also, OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any time for a two-year period beginning January 1, 2007 and ending December 31, 2008. See Note 14 of Notes to Consolidated Financial Statements for a discussion of the Company s short-term debt activity.

ENVIRONMENTAL MATTERS

Approximately $16.5 million and $97.5 million, respectively, of the Company s capital expenditures budgeted for 2007 and 2008 are to comply with environmental laws and regulations. The Company s management believes that all of its operations are in substantial compliance with present federal, state and local environmental standards. It is estimated that the Company s total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $84.4 million during 2007 as compared to approximately $60.1 million in 2006. The Company continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position itself in a competitive market. See Note 17 of Notes to Consolidated Financial Statements for a discussion of environmental matters, including the impact of existing and proposed environmental legislation and regulations.

EMPLOYEES

The Company and its subsidiaries had 3,123 employees at December 31, 2006.

ACCESS TO SECURITIES AND EXCHANGE COMMISSION FILINGS

The Company s web site address is *www.oge.com*. Through the Company s web site under the heading Investors , SEC Filings, the Company makes available, free of charge, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (SEC).

Item 1A. Risk Factors.

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

REGULATORY RISKS

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

We are subject to comprehensive regulation by several federal and state utility regulatory agencies, which significantly influences our operating environment and OG&E s ability to fully recover its costs from utility customers. With rising fuel costs, recoverability of under recovered amounts from our customers is a significant risk. The utility commissions in the states where OG&E operates regulate many aspects of our utility operations including siting and construction of facilities, customer service and the rates that we can charge customers. The profitability of our utility operations is dependent on our ability to fully recover costs related to providing energy and utility services to our customers. As indicated in the settlement agreement with the OCC related to OG&E s Centennial wind farm, OG&E is to file for a general rate review during 2009.

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

We are unable to predict the impact on our operating results from the future regulatory activities of any of the agencies that regulate us. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

OG&E s rates are subject to 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 regulation by the OCC and the APSC, in addition to the FERC. Exposure to inconsistent state and federal regulatory standards may limit our ability to operate profitably. Further alteration of the regulatory landscape in which we operate may harm our financial condition 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, 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 mortality, 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.

We may incur additional costs or delays in power plant construction and may not be able to recover our investment.

OG&E s business plan includes the construction of an estimated 950 MW coal-fired generating plant. OG&E has not recently managed a construction program of this magnitude. There are risks in the completion of this project including, among other things, that actual costs may exceed budget estimates, negotiation of satisfactory engineering, procurement and construction agreements, delays may occur in obtaining permits and materials, construction delays, supplier and contractor performance shortfalls, shortages and inconsistent quality of equipment, materials and labor, work stoppages, adverse weather conditions, environmental and geological conditions, and events beyond OG&E s control may occur that may materially affect the schedule, budget and performance of this project. These risks may increase the costs of this project, require OG&E to purchase additional electricity to supply its retail customers until the project is completed, or both, and may materially affect OG&E s results of operations and financial position. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect our net income and financial position. Furthermore, if the construction project is not completed according to specification, we may incur liabilities and suffer reduced plant efficiency, higher operating costs and reduced net income. If we are unable to complete the construction of the facility or decide to delay or cancel construction of the facility, we may not be able to recover our investment in that facility.

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

Our 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 our facilities were constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements or to provide reliable operations. OG&E currently provides service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates we charge, we would not be able to recover the costs associated with our planned extensive investment. This could adversely affect our results of operations and financial condition. While we may seek to limit the impact of any denied recovery by attempting to reduce the scope of our capital investment, there can no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

Our planned capital investment program coincides with a material increase in the historic prices of the fuels used to generate electricity. Many of our jurisdictions have fuel clauses that permit us to recover these increased 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 condition.

Enogex has announced plans to lease capacity to several proposed new pipeline projects. As part of this process, Enogex may incur significant costs to upgrade and expand its facilities. If the proposed pipeline projects are not completed, Enogex may not be able to recover the costs it incurred to upgrade and expand its facilities.

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 facilities as part of a vertically integrated utility. OG&E is a member of the Southwest Power Pool (SPP) regional transmission organization (RTO) and has transferred operational authority (but not ownership) of OG&E s transmission facilities to the SPP RTO. The SPP RTO implemented a regional energy imbalance service market on February 1, 2007. Without significant actual operating experience in this market, we cannot fully assess the impact this market will have on our business. 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 RTO.

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 an impairment 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.

Recent 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, financial condition and access to capital.

As a result of the volatility of natural gas prices in North America, accounting irregularities at public companies in general, and energy companies in particular, and investigations by governmental authorities into energy trading activities, companies 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 corporations 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, financial condition 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 and liabilities. These changes in accounting standards could lead to negative impacts on reported earnings or increases in liabilities that could, in turn, affect our reported results of operations.

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

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

The Energy Policy Act of 2005 gave the FERC authority to establish mandatory electric reliability rules enforceable with monetary penalties. The FERC has approved the North American Electric Reliability Corporation (NERC) as the Electric Reliability Organization for North America and delegated to it the development and enforcement of electric transmission reliability rules. It is the Company s intent to comply with all applicable reliability rules and expediently correct a violation should it occur. The Company is subject to periodic NERC compliance audits and cannot predict the outcome of those audits.

OPERATIONAL RISKS

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

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

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, similar to the August 14, 2003 black-out in portions of the eastern U.S. and Canada. 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 condition and results of operations.

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

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.

FINANCIAL AND MARKET RISKS

Increasing costs associated with our defined benefit retirement plans, health care plans and other employee-related benefits may adversely affect our results of operations, financial position, or liquidity.

We have defined benefit retirement and postretirement plans that cover substantially all of our employees. Assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions have a significant impact on our earnings and funding requirements. Based on our assumptions at December 31, 2006, we expect to continue to make future contributions to maintain required funding levels. It is our practice to also make voluntary contributions to maintain more prudent funding levels than minimally required. These amounts are estimates and may change based on actual stock market performance, changes in interest rates and any changes in governmental regulations.

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

All employees hired prior to February 1, 2000 participate in defined benefit and postretirement plans. If these employees retire when they become eligible for retirement over the next several years, or if our plan experiences adverse market returns on its investments, or if interest rates materially fall, our pension expense and contributions to the plans could rise substantially over historical levels. The timing and number of employees retiring and selecting the lump sum payment option could result in pension settlement charges that could materially affect our results of operations if we are unable to recover these costs through our electric rates. In addition, assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions, including projected retirements, have a significant impact on our results of operations and consolidated financial position.

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 industry. The median age of utility workers is significantly higher than the national average. Over the next three years, approximately 28% 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, 2006, we had outstanding indebtedness and other liabilities of approximately $3.3 billion. Our subsidiaries are separate legal entities that have no obligation to pay any amounts due on our indebtedness or to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary s ability to pay dividends to us depends on any statutory and contractual restrictions that may be applicable to such subsidiary, which may include requirements to maintain minimum levels of working capital and other assets. Claims of creditors, including general creditors, of our subsidiaries on the assets of these subsidiaries will have priority over our claims generally (except to the extent that we may be a creditor of the subsidiaries and our claims are recognized) and claims by our shareowners.

In addition, as discussed above, OG&E is regulated by state utility commissions in Oklahoma and Arkansas which generally possess broad powers to ensure that the needs of the utility customers are being met. To the extent that the state commissions 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.

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.

Certain provisions in our charter documents and rights plan 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 OGE Energy. 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 OGE Energy 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. Additionally, our rights plan may also delay, defer or prevent a change of control of OGE Energy. Under the rights plan, each outstanding share of common stock has one half of a right attached that trades with the common stock. Absent prior action by our board of directors to redeem the rights or amend the rights plan, upon the consummation of certain acquisition transactions, the rights would entitle the holder thereof (other than the acquiror) to purchase shares of common stock at a discounted price in a manner designed to result in substantial dilution to the acquiror. These provisions could limit the price that investors might be willing to pay in the future for shares of our common stock, discourage third party bidders from bidding for us and could significantly impede the ability of the holders of our common stock to change our management.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot assure that any of our current ratings or 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 in the future so warrant. Any future downgrade could increase the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes. Any downgrade could lead to higher borrowing costs and, if below investment grade, could require us to issue guarantees on behalf of Enogex to support some of OERI s marketing operations.

We are subject to commodity price risk.

We are exposed to commodity price risk in the operations of our Electric Utility segment and our Natural Gas Pipeline segment. To minimize the risk of commodity prices, we may enter into physical or financial derivative instrument contracts to hedge purchase and sale commitments, fuel requirements and inventories of natural gas, distillate fuel oil, electricity, coal and emission allowances. However, financial derivative instrument contracts do not eliminate the risk. Specifically, such risks include commodity price changes and market supply shortages. The impact of these variables could result in our inability to fulfill contractual obligations and significantly higher energy or fuel costs relative to corresponding sales contracts. However, exposure to commodity price risk related to OG&E s retail customers is partially mitigated by its fuel adjustment clause, although we cannot assure that all increases in our commodity prices, including fuel costs, will be completely recovered, or that any such recovery will be timely.

We are also subject to processing margin volatility from keep-whole processing arrangements. Keep-whole processing arrangements generally require a processor of natural gas to keep its shippers whole on a Btu basis by replacing the Btu s of the liquids extracted from the well stream with Btu s of natural gas valued at market prices. Therefore, if natural

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gas prices increase and liquids prices do not increase by a corresponding amount, processing margins are negatively affected. In order to minimize the negative impact on processing margins, processors generally have the flexibility to not recover ethane or ethane/propane depending upon market conditions and residue gas pipeline specifications. Exposure to these keep-whole processing arrangements was reduced, but not eliminated, through new contracts and changes in the SOC that provides for a default processing fee in the event the natural gas liquids revenue less the associated fuel and shrinkage costs is negative. In addition, the Company actively monitors current and future commodity prices for opportunities to hedge its processing margin. Enogex uses forward physical sales and financial instruments to capture these spreads. Despite these activities, we cannot assure that our exposure to keep-whole processing arrangements has been eliminated.

We mark our energy trading portfolio to estimated fair market value on a daily basis (mark-to-market accounting), which causes earnings variability. 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 locations. Actual experience can vary significantly from these estimates and assumptions.

We are subject to credit risk.

We are exposed to credit risks in our generation, retail distribution, pipeline and energy trading 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.

At December 31, 2006, OG&E owns and operates an interconnected electric generation, transmission and distribution system, located in Oklahoma and western Arkansas, which includes eight generating stations with an aggregate capability of approximately 6,079 MW s. The following table sets forth information with respect to OG&E s electric generating facilities, all of which are located in Oklahoma. Also, in January 2007, OG&E s 120 MW Centennial wind farm was fully in service.

Station & Unit		Year Installed	Unit Design Type	Fuel Capability	Unit Run Type	2006 Capacity Factor (A)		Unit Capability (MW)	Station Capability (MW)
Muskogee	3	1956	Steam-Turbine	Gas	Base Load	8.6%		156.5	
	4	1977	Steam-Turbine	Coal	Base Load	76.3%		510.5	
	5	1978	Steam-Turbine	Coal	Base Load	78.9%		521.6	
	6	1984	Steam-Turbine	Coal	Base Load	70.5%		515.0	1,703.6
Seminole	1	1971	Steam-Turbine	Gas	Base Load	18.4%		506.0	
	1GT	1971	Combustion-Turbine	Gas	Peaking	0.1%	(B)	17.0	
	2	1973	Steam-Turbine	Gas	Base Load	23.5%		500.5	
	3	1975	Steam-Turbine	Gas/Oil	Base Load	27.4%		519.0	1,542.5
Sooner	1	1979	Steam-Turbine	Coal	Base Load	69.5%		540.0	
	2	1980	Steam-Turbine	Coal	Base Load	69.9%		512.0	1,052.0
Horseshoe	6	1958	Steam-Turbine	Gas/Oil	Base Load	16.5%		171.7	
Lake	7	1963	Combined Cycle	Gas/Oil	Base Load	10.3%		234.0	
	8	1969	Steam-Turbine	Gas	Base Load	9.5%		387.0	
	9	2000	Combustion-Turbine	Gas	Peaking	5.9%	(B)	45.5	
	10	2000	Combustion-Turbine	Gas	Peaking	5.3%	(B)	45.5	883.7
McClain (C)	1	2001	Combined Cycle	Gas	Base Load	83.2%		363.2	363.2
Mustang	1	1950	Steam-Turbine	Gas	Peaking	1.1%	(B)	54.0	
	2	1951	Steam-Turbine	Gas	Peaking	0.7%	(B)	43.0	
	3	1955	Steam-Turbine	Gas	Base Load	8.9%		117.5	
	4	1959	Steam-Turbine	Gas	Base Load	21.0%		241.0	
	5A	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	1.0%	(B)	34.0	
	5B	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	1.1%	(B)	34.0	523.5
Woodward	1	1963	Combustion-Turbine	Gas	Peaking	0.2%	(B)	10.2	10.2
Enid	1	1965	Combustion-Turbine	Gas	Peaking	---	(D)	---	
	2	1965	Combustion-Turbine	Gas	Peaking	---	(D)	---	
	3	1965	Combustion-Turbine	Gas	Peaking	---	(D)	---	
	4	1965	Combustion-Turbine	Gas	Peaking	---	(D)	---	---
Total Generating Capability (all stations)									6,078.7

(A) 2006 Capacity Factor = 2006 Net Actual Generation / (2006 Net Maximum Capacity (Nameplate Rating in MW s) x Period Hours (8,760 Hours)).
(B) Peaking units, which are used when additional capacity is required, are also necessary to meet the SPP reserve margins.
(C) Represents OG&E s 77 percent ownership interest in the McClain Plant.
(D) These units are currently inactive.

At December 31, 2006, OG&E s transmission system included: (i) 28 substations with a total capacity of approximately 7.7 million kilo Volt-Amps (kVA) and approximately 4,026 structure miles of lines in Oklahoma; and (ii) two substations with a total capacity of approximately 1.9 million kVA and approximately 252 structure miles of lines in Arkansas. OG&E s distribution system included: (i) 347 substations with a total capacity of approximately 10.4 million kVA, 23,486 structure miles of overhead lines, 794 miles of underground conduit and 9,459 miles of underground conductors in Oklahoma; and (ii) 36 substations with a total capacity of approximately 1.59 million kVA, 2,082 structure miles of overhead lines, 73 miles of underground conduit and 619 miles of underground conductors in Arkansas.

At December 31, 2006, Enogex and its subsidiaries owned: (i) approximately 7,757 miles of intrastate natural gas gathering and transportation pipelines in Oklahoma and Texas; (ii) two natural gas storage fields in Oklahoma operating at a working gas level of approximately 23 Bcf with an approximate withdrawal capability of 650 MMcfd and similar injection capability; and (iii) six operating natural gas processing plants with a total inlet capacity of 723 MMcfd, all located in Oklahoma. The following table sets forth information with respect to Enogex s natural gas processing plants:

Processing Plant	Year Installed	Type of Plant	Fuel Capability	2006 Inlet Volumes (MMcfd)	2006 Inlet Capacity (MMcfd)
Calumet	1969	Lean Oil	Gas	111	250
Canute	1996	Cryogenic	Electric	42	60
Cox City	1994	Cryogenic	Gas/Electric	174	180
Harrah	1994	Cryogenic Refrigeration	Gas/Electric	26	38
Thomas	1981	Cryogenic	Gas	93	135
Wetumka	1983	Cryogenic	Gas	37	60
				483	723

During the three years ended December 31, 2006, the Company s gross property, plant and equipment (excluding construction work in progress) additions were approximately $1,090.2 million and gross retirements were approximately $291.1 million. These additions were provided by internally generated funds from operating cash flows, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings. The additions during this three-year period amounted to approximately 17.3 percent of total property, plant and equipment at December 31, 2006.

Item 3. Legal Proceedings.

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies and income tax related items. Management consults with legal counsel and other appropriate experts to assess the claim. If, in management s opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company s Consolidated Financial Statements. Except as set forth below and in Notes 17 and 18 of Notes to Consolidated Financial Statements, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company s consolidated financial position, results of operations or cash flows.

1. United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E. (United States District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al. (United States District Court for the Eastern District of Louisiana, Case No. 97-2089; United States District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with Plaintiff s complaint, which is a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleges: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and Btu content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys fees.

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

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

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

On October 20, 2006, the District Court of Wyoming ruled on Grynberg s appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex Services Corp., Transok, Inc. and OG&E, for lack of subject matter jurisdiction. Judgment was entered on November 17, 2006 and Grynberg filed his notice of appeal with the District Court of Wyoming. The defendants filed motions for attorneys fees regarding issues of liability and Rule 11 motions on January 8, 2007. The defendants also filed for other legal costs on December 18, 2006. A hearing on these motions is currently scheduled for April 24, 2007. Grynberg has also filed appeals with the Tenth Circuit Court of Appeals. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

2. *Will Price (Price I)* On September 24, 1999, various subsidiaries of the Company were served with a class action petition filed in United States District Court, State of Kansas by Quinque Operating Company and other named plaintiffs, alleging mismeasurement of natural gas on non-federal lands. On April 10, 2003 the Court entered an order denying class certification. On May 12, 2003, Plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended petition and the court granted the motion on July 28, 2003. In this amended petition, OG&E and Enogex Inc. were omitted from the case. Two subsidiaries of Enogex remain as defendants. The Plaintiffs amended petition alleges that approximately 60 defendants, including two Enogex subsidiaries, have improperly measured natural gas. The amended petition reduces the claims to: (1) mismeasurement of volume only; (2) conspiracy, unjust enrichment and accounting; (3) a putative Plaintiffs class of only royalty owners; and (4) gas measured in three specific states. A hearing on class certification issues was held April 1, 2005. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

3. *Will Price (Price II)* On May 12, 2003, the Plaintiffs (same as those in Price I above) filed a new class action petition (Price II) in the District Court of Stevens County, Kansas, relating to wrongful Btu analysis against natural gas pipeline owners and operators, naming the same defendants as in the amended petition of the Price I case. Two Enogex subsidiaries were served on August 4, 2003. The Plaintiffs seek to represent a class of only royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The class action petition alleges improper analysis of gas heating content. In all other respects, the Price II petition appears to be the same as the amended petition in Price I. A hearing on class certification issues was held April 1, 2005. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

4. A Notice of Enforcement Action (NOE) by the Texas Natural Resource Conservation Commission (now known as the Texas Commission on Environmental Quality (TCEQ)) was issued to Products, a subsidiary of Enogex, by letter dated July 26, 2002. The NOE relates to the operation of a sulfur recovery unit owned and operated by Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership (Belvan) at its Crockett County, Texas natural gas processing facility. Products sold its interest in Belvan in March 2002. By agreed order dated October 19, 2006, the TCEQ agreed to a fine of less than \$0.1 million. Pursuant to the Agreement of Sale and Purchase with the purchaser, Products retained some liability for amounts that Belvan pays to the TCEQ relating to this NOE not to exceed approximately \$0.1 million. This amount is fully reserved on Products books.

5. On July 22, 2005, Enogex along with certain other unaffiliated co-defendants was served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including the Enogex companies, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs wells. The plaintiffs assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages in excess of \$10,000, plus attorneys fees and costs, and punitive damages in excess of \$10,000. The Enogex

companies filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs right to conduct discovery and the possible re-filing of their allegations in the petition against Enogex companies. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Co. (collectively, BP), filed a cross claim against Enogex

Products Corporation (Products) seeking indemnification and/or contribution from Products based upon the 1997 sale of a third party interest in one of Products natural gas processing plants. On May 17, 2006, the plaintiffs filed an amended petition against the Enogex companies. The Enogex companies filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion was held on November 20, 2006 and the court denied the Enogex companies motion. The Enogex companies filed an answer to the amended petition and BP s cross claim on January 16, 2007. Based on its investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to continue vigorously defending this case.

6. On June 19, 2006, two OG&E customers brought a putative class action, on behalf of all similarly situated customers, in the District Court of Creek County, Oklahoma, challenging certain charges on OG&E s electric bills. The plaintiffs claim that OG&E improperly charged sales tax based on franchise fee charges paid by its customers. The plaintiffs also challenge certain franchise fee charges, contending that such fees are more than is allowed under Oklahoma law. OG&E s motion for summary judgment was denied by the trial judge. OG&E has filed a writ of prohibition at the Oklahoma Supreme Court asking the court to direct the trial court to dismiss the class action suit. At the present time, OG&E believes that this case is without merit and intends to continue vigorously defending this case.

Item 4. Submission of Matters to a Vote of Security Holders.

None.

Executive Officers of the Registrant.

The following persons were Executive Officers of the Registrant as of February 16, 2007:

Name	Age	Title
Steven E. Moore	60	Chairman of the Board and Chief Executive Officer
Peter B. Delaney	53	President and Chief Operating Officer
James R. Hatfield	49	Senior Vice President and Chief Financial Officer
Danny P. Harris	51	Senior Vice President - OGE Energy Corp. and President and Chief Operating Officer - Enogex Inc.
Carla D. Brockman	47	Vice President - Administration / Corporate Secretary
Steven R. Gerdes	50	Vice President - Utility Operations - OG&E
Gary D. Huneryager	56	Vice President - Internal Audits
Jesse B. Langston	44	Vice President - Utility Commercial Operations - OG&E
Cary W. Martin	54	Vice President - Human Resources
Howard W. Motley	58	Vice President - Regulatory Affairs - OG&E
Reid Nuttall	49	Vice President - Enterprise Information and Performance
Melvin H. Perkins, Jr.	58	Vice President - Transmission - OG&E
Paul L. Renfrow	50	Vice President - Public Affairs
Deborah S. Fleming	51	Treasurer; Vice President - Treasurer - OG&E
Scott Forbes	49	Controller and Chief Accounting Officer

Jerry A. Peace	44	Chief Risk and Compliance Officer

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Moore, Delaney, Hatfield, Huneryager, Martin, Nuttall, Renfrow, Forbes and Peace and Ms. Brockman are also officers of OG&E. Each Officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Stockholders, currently scheduled for May 17, 2007.

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

Name		Business Experience
Steven E. Moore	2007 Present:	Chairman of the Board and Chief Executive Officer
	2002 2007:	Chairman of the Board, President and Chief Executive Officer
Peter B. Delaney	2007 Present:	President and Chief Operating Officer
	2004 2007:	Executive Vice President and Chief Operating Officer
	2002 2004:	Executive Vice President, Finance and Strategic Planning OGE Energy Corp. and Chief Executive Officer Enogex Inc.
	2002:	Principal, PD Energy Advisors (consulting firm)
James R. Hatfield	2002 Present:	Senior Vice President and Chief Financial Officer
Danny P. Harris	2005 Present:	Senior Vice President OGE Energy Corp. and President and Chief Operating Officer Enogex Inc.
	2002 2005:	Vice President and Chief Operating Officer Enogex Inc.
Carla D. Brockman	2005 Present:	Vice President Administration / Corporate Secretary
	2002 2005:	Corporate Secretary
	2002:	Assistant Corporate Secretary
	2002:	Client Manager Strategic Planning
Steven R. Gerdes	2003 Present:	Vice President Utility Operations - OG&E
	2002 2003:	Vice President Shared Services
Gary D. Huneryager	2005 Present:	Vice President Internal Audits
	2002 2005:	Internal Audit Officer
	2002:	Assistant Internal Audit Officer
Jesse B. Langston	2006 Present:	Vice President Utility Commercial Operations - OG&E
	2005 2006:	Director Utility Commercial Operations - OG&E
	2004 2005:	Director Corporate Planning - OG&E
	2002 2003:	Manager Corporate Planning - OG&E
Cary W. Martin	2006 Present:	Vice President Human Resources
	2005 2006:	Vice President Global Human Resources SPX Corporation
	2004 2005:	Vice President Human Resources, Technical and Industrial Systems SPX Corporation
	2002 2004:	Vice President Human Resources, Communication and Technology Systems SPX Corporation (global industrial manufacturer)
Howard W. Motley	2006 Present:	Vice President Regulatory Affairs - OG&E
	2004 2006:	Director Regulatory Affairs and Strategy - OG&E
	2003 2004:	Director Regulatory Strategies and Utility Resources - OG&E

	2002 2003:	Manager Regulatory Strategies and Utility Resources - OG&E
	2002:	Manager, Rate Strategies - OG&E
Reid Nuttall	2006 Present:	Vice President Enterprise Information and Performance
	2005 2006:	Vice President Enterprise Architecture National Oilwell Varco (oil and gas equipment company)
	2002 2005:	Chief Information Officer, Vice President Information Technology Varco International (oil and gas equipment company)
Melvin H. Perkins, Jr.	2004 Present:	Vice President Transmission - OG&E
	2002 2003:	Director Transmission Policy - OG&E
	2002:	Manager, Power Delivery Operations - OG&E

Name		Business Experience
Paul L. Renfrow	2005 Present:	Vice President Public Affairs
	2002 2005:	Director Public Affairs
	2002:	Manager, Corporate Communications
Deborah S. Fleming	2006 Present:	Vice President Treasurer - OG&E
	2003 Present:	Treasurer
	2002 2003:	Assistant Treasurer Williams Cos. Inc. (energy company)
Scott Forbes	2005 Present:	Controller and Chief Accounting Officer
	2003 2005:	Chief Financial Officer First Choice Power (retail electric
	2002 2005:	Senior Vice President and Chief Financial Officer Texas
New Mexico Power Company		
	2002:	Vice President Chief Accounting and Information Officer Texas New Mexico Power Company (electric utility)
Jerry A. Peace	2004 Present:	Chief Risk and Compliance Officer
	2002 2004:	Chief Risk Officer
	2002:	Director, Options Trading Enogex Inc.

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.

2005	Dividend Paid	Price High	Low
First Quarter	$ 0.3325	$ 27.59	$ 25.15
Second Quarter	0.3325	29.22	26.11
Third Quarter	0.3325	30.60	27.74
Fourth Quarter	0.3325	28.60	24.41

2006	**Dividend Paid**	**Price High**	**Low**
First Quarter	**$ 0.3325**	**$ 29.60**	**$ 26.34**
Second Quarter	**0.3325**	**35.07**	**28.29**
Third Quarter	**0.3325**	**39.15**	**34.65**
Fourth Quarter	**0.3325**	**40.58**	**36.10**

2007	Dividend Paid	Price High	Low
First Quarter (through January 31)	$ 0.3400	**$ 40.48**	**$ 37.52**

The number of record holders of the Company s Common Stock at January 31, 2007, was 25,093. The book value of the Company s Common Stock at January 31, 2007, was $17.63.

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 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 Enogex, on Enogex s common stock. 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 and the covenants of OG&E s certificate of incorporation and its debt instruments limiting the ability of OG&E to pay dividends.

Under OG&E s certificate of incorporation, if any shares of its preferred stock are outstanding, dividends (other than dividends payable in common stock), distributions or acquisitions of OG&E common stock:

- may not exceed 50 percent of net income for a prior 12-month period, after deducting dividends on any preferred stock during the period, if the sum of the capital represented by the common stock, premiums on capital stock

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

may not exceed 75 percent of net income for such 12-month period, as adjusted if this capitalization ratio is 20 percent or more, but less than 25 percent; and

if this capitalization ratio exceeds 25 percent, dividends, distributions or acquisitions may not reduce the ratio to less than 25 percent except to the extent permitted by the provisions described in the above two bullet points.

Currently, no shares of OG&E preferred stock are outstanding and no portion of the retained earnings of OG&E is presently restricted by this provision.

Issuer Purchases of Equity Securities

The shares indicated below represent shares of Company common stock purchased on the open market by the trustee for the Company s Stock Ownership and Retirement Savings Plan and reflect shares purchased with employee contributions as well as the portion attributable to the Company s matching contributions.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
1/1/06 1/31/06	38,100	$ 27.08	N/A	N/A
2/1/06 2/28/06	26,900	$ 27.42	N/A	N/A
3/1/06 3/31/06	---	$ ---	N/A	N/A
4/1/06 4/30/06	49,500	$ 29.41	N/A	N/A
5/1/06 5/31/06	---	$ ---	N/A	N/A
6/1/06 6/30/06	---	$ ---	N/A	N/A
7/1/06 7/31/06	26,400	$ 37.65	N/A	N/A
8/1/06 8/31/06	---	$ ---	N/A	N/A
9/1/06 9/30/06	14,566	$ 35.09	N/A	N/A
10/1/06 10/31/06	40,500	$ 38.04	N/A	N/A
11/1/06 11/30/06	---	$ ---	N/A	N/A
12/1/06 12/31/06	18,200	$ 39.55	N/A	N/A

N/A not applicable

Company Stock Performance

The following graph shows a five-year comparison of cumulative total returns for the Company s common stock, the S&P 500 Index and the S&P 500 Electric Utilities Index. The graph assumes that the value of the investment in the Company s common stock and each index was 100 at December 31, 2001, and that all dividends were reinvested. As of December 31, 2006, the closing price of the Company s common stock on the New York Stock Exchange was $40.00.

	2001	2002	2003	2004	2005	**2006**
OGE Energy Corp.	100	82	120	139	147	**229**
S&P 500 Index	100	78	100	111	117	**135**
S&P 500 Electric Utilities	100	85	105	133	157	**193**

Item 6. Selected Financial Data.

HISTORICAL DATA

Year ended December 31 SELECTED FINANCIAL DATA *(In millions, except per share data)*	**2006 (A)**	2005 (B)	2004 (B)	2003 (B)	2002 (B)
Operating revenues	**$ 4,005.6**	$ 5,911.5	$ 4,862.6	$ 3,757.4	$ 2,991.8
Cost of goods sold	**2,902.5**	4,942.3	3,937.7	2,841.6	2,105.7
Gross margin on revenues	**1,103.1**	969.2	924.9	915.8	886.1
Other operating expenses	**670.4**	646.8	630.4	617.9	659.5
Operating income	**432.7**	322.4	294.5	297.9	226.6
Interest income	**6.2**	3.5	4.9	1.3	1.7
Allowance for equity funds used during construction	**4.1**	---	0.9	---	---
Other income (loss)	**16.3**	(0.3)	10.5	2.0	2.9
Other expense	**16.7**	5.5	4.7	7.6	4.2
Interest expense	**96.0**	90.3	90.8	92.3	105.1
Income tax expense	**120.5**	68.6	73.4	70.8	43.2
Income from continuing operations	**226.1**	161.2	141.9	130.5	78.7
Income from discontinued operations, net of tax	**36.0**	49.8	11.6	4.7	12.1
Cumulative effect on prior years of change in accounting principle, net of tax of $3.4	**---**	---	---	(5.4)	---
Net income	**$ 262.1**	$ 211.0	$ 153.5	$ 129.8	$ 90.8
Basic earnings (loss) per average common share					
Income from continuing operations	**$ 2.48**	$ 1.79	$ 1.61	$ 1.60	$ 1.01
Income from discontinued operations, net of tax	**0.40**	0.55	0.13	0.06	0.15
Loss from cumulative effect of accounting change, net of tax	**---**	---	---	(0.07)	---
Net income	**$ 2.88**	$ 2.34	$ 1.74	$ 1.59	$ 1.16
Diluted earnings (loss) per average common share					
Income from continuing operations	**$ 2.45**	$ 1.77	$ 1.60	$ 1.59	$ 1.01
Income from discontinued operations, net of tax	**0.39**	0.55	0.13	0.06	0.15
Loss from cumulative effect of accounting change, net of tax	**---**	---	---	(0.07)	---
Net income	**$ 2.84**	$ 2.32	$ 1.73	$ 1.58	$ 1.16
Dividends declared per share	**$ 1.3375**	$ 1.33	$ 1.33	$ 1.33	$ 1.33

(A) The Company adopted Statement of Financial Accounting Standard No. 123 (Revised), Share-Based Payment, using the modified prospective transi

(B) Amounts for 2005 and 2004 were restated for discontinued operations related to the sale of Enogex assets in May 2006, as discussed in Note 8 of Notes

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HISTORICAL DATA (Continued)

Year ended December 31 SELECTED FINANCIAL DATA *(In millions, except per share data)*	**2006 (A)**	2005 (B)	2004 (B)	2003 (B)	2002 (B)
Long-term debt	**$ 1,346.3**	$ 1,350.8	$ 1,424.1	$ 1,436.1	$ 1,501.9
Total assets	**$ 4,902.0**	$ 4,898.9	$ 4,802.9	$ 4,560.4	$ 4,247.5
CAPITALIZATION RATIOS (C)					
Stockholders equity	**54.31%**	50.46%	46.85%	44.65%	39.25%
Long-term debt	**45.69%**	49.54%	53.15%	55.35%	60.75%
RATIO OF EARNINGS TO FIXED CHARGES (D)					
Ratio of earnings to fixed charges	**4.30**	3.37	3.23	3.08	2.10

(A) The Company adopted Statement of Financial Accounting Standard No. 123 (Revised), Share-Based Payment, using the modified prospective trans

(B) Amounts for 2005 and 2004 were restated for discontinued operations related to the sale of Enogex assets in May 2006, as discussed in Note 8 of Note

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

(D) For purposes of computing the ratio of earnings to fixed charges, (1) earnings consist of pre-tax income from continuing operations plus fixed charges,

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

Introduction

OGE Energy Corp. (collectively, with its subsidiaries, the Company) is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through two business segments, the Electric Utility and the Natural Gas Pipeline segments.

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

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries (Enogex) and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. The vast majority of Enogex s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. In May 2006, Enogex Gas Gathering, L.L.C. (Gathering), a wholly-owned subsidiary of Enogex Inc., sold certain gas gathering assets in the Kinta, Oklahoma, area, which have been reported as discontinued operations in the Company s Consolidated Financial Statements (see Results of Operations Enogex Discontinued Operations for a further discussion). In December 2006, Enogex entered into a joint venture arrangement with a third party. The joint venture, Atoka Midstream LLC, intends to construct, own and operate a gathering system and processing plant and related facilities relating to production in certain areas in southeastern Oklahoma. Enogex holds its 50 percent membership interest in Atoka Midstream LLC through Enogex

Atoka LLC (Enogex Atoka), a wholly-owned subsidiary of Enogex Inc. Enogex Atoka will act as the managing member and operator of the facilities owned by the joint venture.

Executive Overview

The Company s vision is to be a regional utility-focused energy business recognized for operational excellence and strong financial performance. The Company intends to execute its vision by focusing on its regulated electric utility business and unregulated midstream gas business. As explained below, the Company intends to maintain the majority of its assets in the regulated utility business complemented by its natural gas pipeline business. The Company s long-term financial goals include earnings growth of four to five percent on a weather-normalized basis, an annual total return in the top third of its peer group, dividend growth, maintenance of a dividend payout ratio consistent with its peer group, maintenance of strong credit ratings and appropriate returns on invested capital. The Company believes it can accomplish these financial goals by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and maintaining strong regulatory and legislative relationships.

OG&E has been focused on its Customer Savings and Reliability Plan, which provides for increased investment at the utility to improve reliability and meet load growth, replace infrastructure equipment, replace aging transmission and distribution system and deploy newer technology that improves operational, financial and environmental performance. As part of this plan, OG&E purchased, for approximately $160 million, a 77 percent interest in the 520 megawatt (MW) natural gas-fired combined cycle NRG McClain Station (the McClain Plant) in July 2004. Capacity payment savings from reduced cogeneration payments and fuel savings from the McClain Plant will be utilized to help mitigate the price increases associated with this investment. Also, as part of this plan, on February 20, 2006, OG&E entered into an agreement to engineer, procure and construct a wind generation energy system for a 120 MW wind farm (Centennial) in northwestern Oklahoma. The wind farm was fully in service in January 2007. Through December 31, 2006, OG&E has spent approximately $171.1 million related to the Centennial wind farm. On January 17, 2007, OG&E sent notice to the OCC to trigger the Centennial wind farm rider for the first billing cycle in February 2007. OG&E has announced a six-year construction initiative that is estimated to include up to $3.3 billion in major projects designed to expand capacity, enhance reliability and improve environmental performance. The first part of this initiative involved OG&E entering into an agreement for the proposed construction of a 950 MW coal unit at OG&E s existing Sooner plant location near Red Rock, Oklahoma. OG&E expects construction to begin in 2007 and is targeting the completion of the power plant in the 2011/2012 timeframe. OG&E s share of the projected $1.8 billion construction cost for the plant will be about $759 million. OG&E s six-year construction initiative also includes strengthening and expanding the electric transmission, distribution and substation systems and replacing aging infrastructure. Other projects involve installing new emission-control equipment at existing OG&E power plants to help meet OG&E s commitment to meet environmental requirements. OG&E also expects to incur a significant amount of capital and operating expenditures in the next several years to comply with current and future environmental laws and regulations. For additional information regarding the above items and other regulatory matters, see Note 18 of Notes to Consolidated Financial Statements.

Enogex plans to continue to implement improvements to enhance long-term financial performance of its mid-continent assets through more efficient operations and effective commercial management of the assets. In addition, Enogex is seeking to diversify its gathering, processing and transportation businesses principally by expanding into other geographic areas that are complementary with the Company s strategic capabilities. In August 2006, Enogex completed a project to expand its gathering pipeline capacity on the west side of its system in western Oklahoma and the Texas Panhandle that should enable Enogex to benefit from growth opportunities in that marketplace. Enogex continues to consider additional opportunities to expand this project. In addition to focusing on growing its earnings, Enogex has reduced its exposure to changes in commodity prices and minimized its exposure to keep-whole processing arrangements. Enogex s profitability increased significantly from 2003 to 2006 due to the performance improvement plan initiated in 2002 as well as an overall favorable business environment coupled with higher commodity prices. While the Company believes substantial progress has been achieved, additional opportunities remain. Enogex continues to review its work processes, evaluate the rationalization of assets, negotiate better terms for both new contracts and replacement contracts, manage costs and pursue opportunities for organic growth, all in an effort to further improve its cash flow and net income, while at the same time decreasing the volatility associated with commodity prices. Enogex s marketing business, which concentrates principally on origination of physical sales of natural gas, has expanded into the Gulf Coast and Rocky Mountain markets. Also, Enogex s marketing business utilizes a strategy that seeks to minimize the amount of capital employed and to complement better the natural gas pipeline business. The Company expects to continue to pursue a disciplined approach to continuous improvement and efficiency of operations. Also, during 2005 and 2006, Enogex sold its interests in Enogex Arkansas Pipeline Corporation (EAPC) and Enerven Compression Services, LLC (Enerven) and certain gas gathering assets in the Kinta, Oklahoma area (the Kinta Assets) and will continue to review its asset portfolio and seek to divest underperforming or non-strategic

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assets. Also, on December 15, 2006, Enogex announced that it had entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC for a primary term of 10 years (subject to possible extensions) for certain capacity on the Enogex system. The leased capacity provided for in this agreement is up to 0.5 billion cubic feet (Bcf) per day and is dependent on the shipper volumes that commit to the project. The Enogex capacity will be part of the proposed Midcontinent Express Pipeline (MEP), a joint venture between Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. In addition to the Enogex leased capacity, the proposed MEP project includes a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Pending necessary regulatory approval, the MEP pipeline project is currently expected to be in service by February 2009. Depending on the final capacity that MEP subscribes to pursuant to the agreement, Enogex expects its revenues from this firm capacity lease agreement to be between $12 million and $30 million annually. Enogex currently estimates that its capital expenditures related to this project during the next two to three years could be approximately $100 million. The Enogex lease agreement with the MEP is subject to certain contingencies including regulatory approval. Prior to such approval, Enogex may incur expenditures of between approximately $20 million and $40 million with the majority being for certain commitments for materials that can be sold or used in normal operations in the event the MEP project does not proceed and the amount not recovered or utilized for such expenditures is not expected to be material. Enogex also is seeking to provide lease capacity to Boardwalk s Gulf Crossings project. Boardwalk Pipeline Partners, LP, has announced plans to build the Gulf Crossings pipeline, which includes 355 miles of new interstate natural gas pipeline. It initially is expected to transport gas from the supply areas in Sherman, Texas, Bennington, Oklahoma and Paris, Texas to the Perryville, Louisiana Hub. Subject to regulatory approvals, the Gulf Crossings project is expected to be in service during the fourth quarter of 2008.

The Company s business strategy is to continue maintaining the diversified asset position of OG&E and Enogex so as to provide competitive energy products and services to customers primarily in the south central United States. The Company will continue to focus on those products and services with limited or manageable commodity exposure. In addition to the incremental growth opportunities that Enogex provides, the Company believes that many of the risk management practices, commercial skills and market information available from Enogex provide value to all of the Company s businesses.

In December 2006, the Company and OG&E increased their aggregate available borrowing capacity under their revolving credit agreements from $750.0 million to $1.0 billion, $600 million for the Company and $400 million for OG&E. Each of the credit facilities has a five-year term with an option to extend the term for two additional one-year periods. Also, each of these credit facilities has an additional option at the end of the two renewal options to convert the outstanding balance to a one-year term loan. These revolving credit agreements will provide sufficient liquidity to meet the Company s daily operational needs, capital improvements at OG&E and expansion projects at Enogex.

Overview

Summary of Operating Results

2006 compared to 2005. The Company reported net income of approximately $262.1 million, or $2.84 per diluted share, in 2006 as compared to approximately $211.0 million, or $2.32 per diluted share, in 2005. The increase in net income during 2006 as compared to 2005 was primarily due to:

- OG&E reported net income of approximately $149.3 million, or $1.62 per diluted share of the Company s common stock, in 2006 as compared to approximately $129.7 million, or $1.43 per diluted share, in 2005;
- Enogex s operations, including discontinued operations, reported net income of approximately $113.5 million, or $1.23 per diluted share of the Company s common stock (of which $0.39 per diluted share was attributable to discontinued operations), in 2006 as compared to approximately $89.8 million, or $0.99 per diluted share (of which $0.55 per diluted share was attributable to discontinued operations) in 2005; and
- a net loss at the holding company of approximately $0.7 million, or $0.01 per diluted share, in 2006 as compared to a net loss of approximately $8.5 million, or $0.10 per diluted share, in 2005 primarily due to higher income tax benefits in 2006 as a result of recording the Employee Stock Ownership Plan (ESOP) dividend deduction at the holding company in 2006 which was previously recorded at OG&E in 2005.

2005 compared to 2004. The Company reported net income of approximately $211.0 million, or $2.32 per diluted share, in 2005 as compared to approximately $153.5 million, or $1.73 per diluted share, in 2004. The increase in net income during 2005 as compared to 2004 was primarily due to:

OG&E reported net income of approximately $129.7 million, or $1.43 per diluted share of the Company s common stock, in 2005 as compared to approximately $107.6 million, or $1.22 per diluted share, in 2004;

Enogex s operations, including discontinued operations, reported net income of approximately $89.8 million, or $0.99 per diluted share of the Company s common stock (of which $0.55 per diluted share was attributable to discontinued operations), in 2005 as compared to approximately $60.7 million, or $0.69 per diluted share (of which $0.13 per diluted share was attributable to discontinued operations), in 2004; and

a net loss at the holding company of approximately $8.5 million, or $0.10 per diluted share, in 2005 as compared to a net loss of approximately $14.8 million, or $0.18 per diluted share, in 2004 primarily due to lower interest expense of approximately $9.2 million in 2005 partially offset by a lower income tax benefit of approximately $3.8 million in 2005 due to a lower taxable loss in 2005.

Recent Developments

OG&E Wind Power Filing

As discussed above, in January 2007, the Centennial wind farm in northwestern Oklahoma was fully in service. Through December 31, 2006, OG&E has spent approximately $171.1 million related to the Centennial wind farm. The OCC previously had approved a settlement agreement approving the Centennial wind power contract and a recovery rider for up to $205 million in construction costs and allowance for funds used during construction. The settlement also indicated that OG&E shall file for a general rate review during 2009 that will permit the OCC to issue an order no later than December 31, 2009 placing the Centennial wind farm in OG&E s rate base. On January 17, 2007, OG&E sent notice to the OCC to trigger the Centennial wind farm rider for the first billing cycle in February 2007. The recovery rider is designed to recover approximately $22.6 million in the first year of operations, which amount will decline over the life of the facility. Because the wind farm rider was implemented in February 2007, OG&E expects to recover approximately $20.7 million under the rider during the remaining 11 months of 2007. OG&E expects the recovery rider to remain in effect through late 2009. As explained below, the recent rate order from the APSC allows for the recovery of the portion of the Centennial wind farm allocable to OG&E s customers in Arkansas.

OG&E Arkansas Rate Case Filing

On July 28, 2006, OG&E filed with the APSC an application for an annual rate increase of approximately $13.5 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant, the Centennial wind power project and the costs of electric system expansion and upgrades based on a return on equity of 11.75 percent. On November 29, 2006, OG&E reached a settlement with the other parties in this case for an annual rate increase of approximately $5.4 million. In the settlement agreement, the parties also agreed that OG&E would be allowed to recover the full Arkansas portion of the Centennial wind farm. On January 5, 2007, the APSC approved the settlement and issued a rate order that provides for a $5.4 million annual increase in OG&E s electric rates and a 10.0 percent return on equity. The new Arkansas rates became effective in February 2007.

Proposed Construction of Power Plant

As discussed above, OG&E has entered into a contract with American Electric Power s subsidiary, Public Service Company of Oklahoma (PSO), and the Oklahoma Municipal Power Authority (OMPA) to build a new 950 MW coal unit at OG&E s existing Sooner plant location near Red Rock, Oklahoma. The estimated $1.8 billion project is the result of PSO s December 2005 request for proposals in which it sought bids for up to 600 MW s of new base load generation to be available to PSO. The unit, to be called Red Rock, is expected to be one of the cleanest of its size using coal from the Powder River Basin, which is located near Gillette, Wyoming. OG&E will operate the facility and expects to spend approximately $759 million in construction costs related to its 42 percent ownership percentage in the project and approximately $30 million in transmission costs for the project. PSO will own 50 percent and the OMPA will own eight percent. On December 1, 2006, OG&E submitted an application to the Oklahoma Department of Environmental Quality (ODEQ) for an air permit for the Red Rock plant. OG&E is seeking to have the air permit approved by the ODEQ by August 1, 2007. OG&E expects construction to begin in 2007 and is targeting the completion of the power plant in the 2011/2012 timeframe. OG&E filed an application with the OCC on January 17, 2007 asking the OCC to find that its portion of the construction costs are prudent and that a recovery mechanism should be established to recover OG&E s overall cost of capital on the investment during the construction period. The OCC rules provide that the OCC has up to 240 days to issue an order determining OG&E s pre-approval request, however OG&E s application requested that the OCC issue an order by July 20, 2007. The project is contingent upon numerous factors, including the successful completion of contract negotiations and the necessary regulatory and environmental approvals. Under the construction, ownership and operating agreement between OG&E, PSO and the OMPA, the parties could incur up to $60 million (of which approximately $25 million would be borne by OG&E) prior to the receipt of acceptable regulatory approvals and permits. If such approvals and permits were not obtained and the Red Rock project was abandoned, the Company can provide no assurance that these expenditures incurred by OG&E would be recoverable in future rates.

Enogex Expansion Projects

In August 2006, Enogex completed a project to expand its gathering pipeline capacity on the west side of its system in western Oklahoma and the Texas Panhandle that should enable Enogex to benefit from growth opportunities in that marketplace. Enogex continues to consider additional opportunities to expand this project.

Termination of Continental Connector Project

Enogex had previously announced that it had entered into a letter of intent with El Paso Corporation (El Paso) relating to El Paso s Continental Connector Project. The letter of intent contemplated arrangements by which El Paso or an affiliate would execute a lease of capacity on the Enogex pipeline system and the leased Enogex pipeline capacity would become part of the Continental Connector Project. The letter of intent expired on April 28, 2006. In early October 2006, El Paso determined not to proceed with its proposed Continental Connector project. Enogex did not incur any material expenditures relating to this proposed project.

Oklahoma City Dayton Tire Plant Closing

In July 2006, the Boards of Directors of Bridgestone Firestone North American Tire and its parent company, Bridgestone Americas Holding Inc., approved the closing of the Oklahoma City Dayton tire plant, which closed in December 2006. The closing of this plant is expected to reduce net income by approximately $1.1 million, or $0.01 per diluted share, in 2007.

2007 Outlook

The Company previously disclosed in its Form 10-Q for the quarter ended September, 2006 that its 2007 earnings guidance was $213 million to $231 million of income from continuing operations, or $2.30 to $2.50 per diluted share. The Company has reaffirmed the 2007 earnings guidance, which excludes any gains on asset sales and assumes approximately 92.5 million average diluted shares outstanding and an effective tax rate of 32.6 percent. The Company is currently projecting earnings toward the lower half of the guidance due to refinements of its prior estimates based on its 2006 audited financial results and numerous other factors. At the utility, these factors include reduced tariffs for fuel-related costs, the slight delay in implementing the Centennial wind farm rider and increased depreciation expense, offset in part by higher anticipated margin growth. At Enogex, a key factor was the recognition of mark-to-market gains in the marketing business in the fourth quarter of 2006 that were previously anticipated for the first quarter of 2007. Projected cash flow from operations of between $371 million and $389 million for 2007 has been lowered to $336 million to $354 million primarily due to the collection by OG&E during 2006 under approved tariffs of approximately $26.7 million of additional fuel-related revenues that was not intended by the OCC rate order in December 2005. The $26.7 million, plus interest, will be credited to OG&E s Oklahoma customers in 2007 and 2008 through OG&E s automatic fuel adjustment clause and reduced tariffs were filed, effective December 31, 2006, that will cease the continued recovery of these additional fuel-related revenues. See Financial Condition below.

Earnings guidance per

(In millions, except per share data)	2006 10-K Dollars	Diluted EPS
OG&E	$154 - $162	$1.67 - $1.75
Enogex	$63 - $72	$0.68 - $0.78
Holding Company	($3) - ($4)	($0.03) - ($0.05)
Total	$213 - $231	$2.30 - $2.50

Key assumptions for 2007 are:

As shown above, OG&E s earnings guidance has been reaffirmed at $154 million to $162 million. Key factors and assumptions underlying this guidance include:

OG&E

Normal weather patterns are experienced for the year;

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- Gross margin on revenues (gross margin) on weather-adjusted, retail electric sales increases approximately two percent;
- Centennial wind farm rider increase of approximately $21 million;
- Arkansas rate increase of approximately $5 million which began in February 2007;
- Operating expenses increase approximately $28 million primarily due to higher employee costs and higher depreciation;
- Interest costs increase approximately $7 million primarily due to higher levels of long-term and short-term debt;
- Tax credit of approximately $11 million associated with the Centennial wind farm; and
- Capital expenditures for investment in OG&E s generation, transmission and distribution system are approximately $427 million in 2007, which includes capital expenditures of up to $94 million associated with OG&E s Red Rock generating plant.

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

Enogex

As shown above, Enogex s earnings guidance remains unchanged from $63 million to $72 million, or $0.68 to $0.78 per diluted share. Key factors and assumptions underlying this guidance include:

- Total Enogex anticipated gross margin of approximately $312 million to $328 million as compared to approximately $307 million in 2006. The 2007 guidance includes:
  - Transportation and storage gross margin contribution of approximately $136 million. As compared to 2006, margins are projected to increase approximately $11 million primarily in the storage business as a result of new contracts and higher storage fees.
  - Gathering and processing gross margin contribution of approximately $168 million to $183 million as compared to approximately $168 million in 2006. Key factors affecting the gathering and processing gross margin are:
    - Gross margin decrease in Enogex s gathering and processing business in 2007 primarily due to lower commodity spreads offset by higher contractual gains as a result of higher natural gas prices;
    - Increase of 13 percent in volumes in Enogex s gathering business as compared to 2006 primarily due to new business;
    - Forecasted natural gas prices of $6.33 to $6.62 per Million British thermal unit (MMBtu) in 2007 as compared to $6.04 in 2006;
    - Forecasted commodity spreads of $2.69 to $3.21 per MMBtu in 2007 as compared to $3.99 per MMBtu assumed in 2006;
    - Forecasted average natural gas liquids prices of $0.93 to $1.02 per gallon in 2007 as compared to $1.10 per gallon in 2006; and
    - Enogex s gathering and processing business is projecting approximately 318 new well connects in 2007 including wells behind central receipt points.
  - Marketing gross margin contribution of approximately $9 million in 2007 as compared to approximately $14 million in 2006 primarily due to the recognition of mark-to-market hedging gains in 2006.
- Operating expenses increase approximately $16 million primarily due to increased employee costs associated with new business growth and higher depreciation costs;

Other income decreases approximately $16 million from 2006 as a result of lower interest income due to the redeployment of cash from assets sales and the result of a legal settlement received in 2006;
Interest expense remains relatively flat in 2007; and

Capital expenditures for investment in Enogex s pipeline system are approximately $125 million in 2007.

Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets have not been included in the 2007 earnings guidance.

Holding Company

As shown above, the projected loss at the holding company is $3 million to $4 million, or $0.03 to $0.05 per diluted share, primarily due to projected interest costs.

Dividend Policy

The Company s dividend policy is reviewed by the Board of Directors at least annually and is based on numerous factors, including management s estimation of the long-term earnings power of its businesses. The target payout ratio for the Company is to pay out as dividends no more than 65 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of our shareholder base, our financial position, our growth targets, the composition of our assets and investment opportunities. At the Company s November 2006 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 $0.34 per share from $0.3325 per share payable in the first quarter of 2007.

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, 2006, 2005 and 2004 and the Company s consolidated financial position at December 31, 2006 and 2005. 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)*	**2006**	2005	2004
Operating income	**$ 432.7**	$ 322.4	$ 294.5
Net income	**$ 262.1**	$ 211.0	$ 153.5
Basic average common shares outstanding	**91.0**	90.3	88.0
Diluted average common shares outstanding	**92.1**	90.8	88.5
Basic earnings per average common share	**$ 2.88**	$ 2.34	$ 1.74
Diluted earnings per average common share	**$ 2.84**	$ 2.32	$ 1.73
Dividends declared per share	**$ 1.3375**	$ 1.33	$ 1.33

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 unusual or infrequent items, the cost of capital and income taxes.

Operating Income (Loss) by Business Segment

Year ended December 31 *(In millions)*	**2006**	2005	2004
OG&E (Electric Utility)	**$ 293.9**	$ 232.2	$ 192.3
Enogex (Natural Gas Pipeline)	**138.8**	89.6	103.3
Other Operations (A)	**---**	0.6	(1.1)
Consolidated operating income	**$ 432.7**	$ 322.4	$ 294.5

(A) Other Operations primarily includes unallocated corporate expenses and consolidating eliminations.

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

OG&E

Year ended December 31 *(Dollars in millions)*	**2006**	2005	2004
Operating revenues	**$ 1,745.7**	$ 1,720.7	$ 1,578.1
Cost of goods sold	**950.0**	994.2	914.2
Gross margin on revenues	**795.7**	726.5	663.9
Other operation and maintenance	**316.5**	309.2	301.9
Depreciation	**132.2**	134.4	122.7
Taxes other than income	**53.1**	50.7	47.0
Operating income	**293.9**	232.2	192.3
Interest income	**1.9**	2.6	2.7
Allowance for equity funds used during construction	**4.1**	---	0.9
Other income (loss)	**4.0**	(2.8)	4.5
Other expense	**9.7**	2.5	2.3
Interest expense	**60.1**	47.2	37.5
Income tax expense	**84.8**	52.6	53.0
Net income	**$ 149.3**	$ 129.7	$ 107.6
Operating revenues by classification			
Residential	**$ 698.8**	$ 663.6	$ 611.4
Commercial	**428.3**	418.9	389.9
Industrial	**345.0**	355.6	326.7
Public authorities	**171.0**	173.1	158.5
Sales for resale	**65.4**	67.7	57.0
Provision for rate refund	**(0.9)**	(2.0)	(6.9)
System sales revenues	**1,707.6**	1,676.9	1,536.6
Off-system sales revenues	**2.7**	4.9	0.8
Other	**35.4**	38.9	40.7
Total operating revenues	**$ 1,745.7**	$ 1,720.7	$ 1,578.1
MWH (A) sales by classification (in millions)			
Residential	**8.7**	8.5	7.9
Commercial	**6.2**	6.0	5.7
Industrial	**7.1**	7.2	7.0
Public authorities	**2.9**	2.8	2.7
Sales for resale	**1.5**	1.5	1.4
System sales	**26.4**	26.0	24.7
Off-system sales	**---**	0.1	0.1
Total sales	**26.4**	26.1	24.8
Number of customers	**754,840**	745,493	735,008
Average cost of energy per KWH (B) - cents			
Fuel	**3.040**	3.011	2.887
Fuel and purchased power	**3.398**	3.300	3.436
Degree days (C)			
Heating			
Actual	**2,746**	3,159	3,114
Normal	**3,631**	3,631	3,650
Cooling			
Actual	**2,485**	2,163	1,839
Normal	**1,911**	1,911	1,911

(A) Megawatt-hour.

(B) Kilowatt-hour.

(C) 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 a

2006 compared to 2005. OG&E s operating income increased approximately $61.7 million or 26.7 percent in 2006 as compared to 2005 primarily due to higher gross margins partially offset by higher operating expenses.

Gross margin, which is operating revenues less cost of goods sold, was approximately $795.7 million in 2006 as compared to approximately $726.5 million in 2005, an increase of approximately $69.2 million, or 9.5 percent. The gross margin increased primarily due to:

- price variance primarily due to rate increases authorized in the OCC order in December 2005, which increased the gross margin by approximately $47.6 million;
- new customer growth in OG&E s service territory, which increased the gross margin by approximately $10.9 million;
- increased peak demand by industrial customers in OG&E s service territory, which increased the gross margin by approximately $6.7 million; and
- warmer weather in OG&E s service territory, which increased the gross margin by approximately $6.2 million.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $730.3 million in 2006 as compared to approximately $795.4 million in 2005, a decrease of approximately $65.1 million or 8.2 percent 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 2006 and 2005, respectively, OG&E s fuel mix was 67 percent coal and 33 percent natural gas and 70 percent coal and 30 percent natural gas. Though OG&E has a higher installed capability of generation from natural gas units of 57 percent, it has been more economical to generate electricity for our customers with lower priced coal. Purchased power costs were approximately $219.7 million in 2006 as compared to approximately $198.8 million in 2005, an increase of approximately $20.9 million or 10.5 percent. This increase was primarily due to a power purchase contract that allowed OG&E to make economic purchases during peak demand summer months.

Other operating and maintenance expenses were approximately $316.5 million in 2006 as compared to approximately $309.2 million in 2005, an increase of approximately $7.3 million or 2.4 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages and other employee benefits of approximately $12.5 million;
- higher allocations from the holding company of approximately $3.9 million primarily due to an increase in incentive compensation;
- higher bad debt expense of approximately $3.5 million; and
- an additional accrual of approximately $2.2 million for the settlement of a claim.

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

- a decrease in outside services of approximately $9.3 million; and
- an increase in capitalized work of approximately $6.4 million primarily due to increased labor and transportation expenses related to more capital projects in 2006.

The other operating and maintenance expense variance includes other operating and maintenance expenses associated with the acquisition of the McClain Plant, which expenses ceased being recorded as a regulatory asset on July 8, 2005.

Depreciation expense was approximately $132.2 million in 2006 as compared to approximately $134.4 million in 2005, a decrease of approximately $2.2 million or 1.6 percent. The decrease in depreciation expense was primarily due to:

- a decrease in depreciation rates that was implemented January 1, 2006 as approved by the OCC in December 2005; and
- a decrease due to the retirement of assets at June 30, 2006 related to a power supply contract with a large industrial customer that expired June 1, 2006.

These decreases in depreciation expense were partially offset by a full year of depreciation expense in 2006 associated with the acquisition of the McClain Plant.

Taxes other than income were approximately $53.1 million in 2006 as compared to approximately $50.7 million in 2005, an increase of approximately $2.4 million or 4.7 percent, primarily due to increased ad valorem taxes. This variance includes ad valorem taxes associated with the acquisition of the McClain Plant, which expenses ceased being recorded as a regulatory asset on July 8, 2005.

Allowance for equity funds used during construction was approximately $4.1 million in 2006 due to construction costs associated with OG&E s Centennial wind farm that exceeded the average daily short-term borrowings in 2006. There was no allowance for equity funds used during construction in 2005.

Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating income. Other income was approximately $4.0 million in 2006 as compared to a reduction in other income of approximately $2.8 million in 2005, an increase in other income of approximately $6.8 million. The increase in other income was primarily due to:

- a gain of approximately $3.5 million from the sale of miscellaneous assets that were recorded in 2004 and were reclassified to a regulatory liability in 2005; and
- the benefit associated with the tax gross-up of approximately $4.1 million of allowance for equity funds used during construction.

Other expense includes, among other things, expenses from losses on the sale and retirement of assets, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions and expenses. Other expense was approximately $9.7 million in 2006 as compared to approximately $2.5 million in 2005, an increase of approximately $7.2 million primarily due to a loss on the retirement of fixed assets of approximately $6.0 million.

Interest expense was approximately $60.1 million in 2006 as compared to approximately $47.2 million in 2005, an increase of approximately $12.9 million or 27.3 percent. The increase in interest expense was primarily due to:

- increased interest of approximately $7.7 million due to the one-time recognition of interest expense associated with a certain water storage agreement;
- increased interest of approximately $4.8 million on debt associated with the McClain Plant acquisition, which OG&E ceased recording as a regulatory asset on July 8, 2005;
- increased interest of approximately $3.0 million due to the termination of an interest rate swap in 2005; and
- increased interest of approximately $1.5 million due to increased borrowings from the holding company to cover increased construction costs.

These increases in interest expense were partially offset by:

- a decrease in interest expense due to an increase in the allowance for borrowed funds used during construction of approximately $2.3 million; and
- a decrease in interest expense of approximately $1.9 million related to the Company making a deposit with the Internal Revenue Service (IRS) in August 2006 in anticipation that a portion of prior year deductions will be disallowed, which enabled OG&E to cease accruing interest in August 2006.

Income tax expense was approximately $84.8 million in 2006 as compared to approximately $52.6 million in 2005, an increase of approximately $32.2 million or 61.2 percent. The increase in income tax expense was primarily due to:

higher pre-tax income for OG&E;

the ESOP dividend deduction at the holding company in 2006 which was previously recorded at OG&E in 2005 of approximately $7.4 million; and
a decrease in state tax credits in 2006 of approximately $3.8 million.

2005 compared to 2004. OG&E s operating income increased approximately $39.9 million or 20.7 percent in 2005 as compared to 2004 primarily attributable to higher gross margins partially offset by higher operating expenses.

Gross margin was approximately $726.5 million in 2005 as compared to approximately $663.9 million in 2004, an increase of approximately $62.6 million or 9.4 percent. The gross margin increased primarily due to:

warmer weather in OG&E s service territory, which increased the gross margin by approximately $33.4 million;

price variance due to sales and customer mix and rate increases authorized in the OCC order in December 2005 that are included in the unbilled revenue calculation at December 31, 2005, which increased the gross margin by approximately $13.2 million;

new customer growth primarily in the residential and commercial sectors of OG&E s service territory, which increased the gross margin by approximately $6.6 million; and

increased demand by industrial customers in OG&E s service territory, which increased the gross margin by approximately $5.8 million.

Fuel expense was approximately $795.4 million in 2005 as compared to approximately $645.1 million in 2004, an increase of approximately $150.3 million or 23.3 percent. The increase was primarily due to increased generation and a higher average cost of fuel per kwh. 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 2005 and 2004, OG&E s fuel mix was 70 percent coal and 30 percent natural gas. Though OG&E has a higher installed capability of generation from natural gas units of 58 percent, it has been more economical to generate electricity for our customers with lower priced coal. Purchased power costs were approximately $198.8 million in 2005 as compared to approximately $269.1 million in 2004, a decrease of approximately $70.3 million or 26.1 percent. The decrease was primarily due to OG&E s completion of the acquisition of the McClain Plant in 2004, the termination of a power purchase contract in August 2004 which was replaced with a new contract in September 2004 and the scheduled decrease in cogeneration capacity payments for another power purchase contract, which became effective in January 2005.

Other operating and maintenance expenses were approximately $309.2 million in 2005 as compared to approximately $301.9 million in 2004, an increase of approximately $7.3 million or 2.4 percent. The increase in other operating and maintenance expenses was primarily due to:

higher salaries, wages, pension and other employee expenses of approximately $8.6 million; and

higher materials and supplies expense of approximately $2.0 million.

These increases in other operating and maintenance expenses were partially offset by lower allocations from the holding company of approximately $6.9 million primarily due to lower miscellaneous corporate expenses. This variance includes other operating and maintenance expenses associated with the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.

Depreciation expense was approximately $134.4 million in 2005 as compared to approximately $122.7 million in 2004, an increase of approximately $11.7 million or 9.5 percent, primarily due to a higher level of depreciable plant in addition to depreciation expense associated with the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.

Taxes other than income were approximately $50.7 million in 2005 as compared to approximately $47.0 million in 2004, an increase of approximately $3.7 million or 7.9 percent, primarily due to increased ad valorem taxes. This variance includes ad valorem taxes associated with the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.

There was a reduction in other income of approximately $2.8 million in 2005 as compared to income of approximately $4.5 million in 2004, a decrease of approximately $7.3 million. The decrease in other income was primarily due to gains recognized in 2004 of approximately $3.5 million from the sale of OG&E s interests in its natural gas producing properties and the sale of land near the Company s principal executive offices which gains were reversed in 2005 and reclassified to Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheet as a regulatory liability. Also contributing to the decrease in other income was a gain in 2004 of approximately $0.6 million from the repurchase of outstanding heat pump loans.

Interest expense was approximately $47.2 million in 2005 as compared to approximately $37.5 million in 2004, an increase of approximately $9.7 million or 25.9 percent. The increase in interest expense was primarily due to:

- increased interest of approximately $4.3 million due to interest on debt associated with the McClain Plant acquisition, which OG&E ceased recording as a regulatory asset on July 8, 2005;

increased interest of approximately $4.2 million due to an increase in variable interest rates associated with the Company s interest rate swap agreement and variable-rate industrial authority bonds; and
increased interest of approximately $3.3 million for additional interest expense related to income taxes as a result of new guidelines issued by the IRS related to a change in the method of accounting used to capitalize costs for self-construction for income tax purposes only.

These increases in interest expense were partially offset by:

a decrease in interest expense of approximately $1.2 million due to lower interest rates on short-term debt used to temporarily fund the repayment of higher cost matured and called long-term debt; and
a decrease in interest expense of approximately $0.5 million due to an increase in the allowance for borrowed funds used during construction.

Income tax expense was approximately $52.6 million in 2005 as compared to approximately $53.0 million in 2004, a decrease of approximately $0.4 million or 0.8 percent. The decrease in income tax expense was primarily due to:

a reduction in tax accruals in 2005 related to Medicare Part D of approximately $2.6 million;

a reduction in excess deferred taxes in 2005 of approximately $2.1 million; and

an increase in Oklahoma state income tax credits of approximately $0.6 million in 2005 as compared to 2004.

These decreases in income tax expense were partially offset by higher pre-tax income for OG&E.

Enogex Continuing Operations

Year ended December 31 *(Dollars in millions)*	**2006**	2005	2004
Operating revenues	**$ 2,367.8**	$ 4,332.4	$ 3,379.9
Cost of goods sold	**2,060.4**	4,090.4	3,118.2
Gross margin on revenues	**307.4**	242.0	261.7
Other operation and maintenance	**110.0**	96.6	93.5
Depreciation	**42.3**	40.4	41.1
Impairment of assets	**0.3**	---	7.8
Taxes other than income	**16.0**	15.4	16.0
Operating income	**138.8**	89.6	103.3
Interest income	**11.1**	2.9	3.2
Other income	**7.7**	0.8	4.5
Other expense	**0.3**	0.3	0.3
Interest expense	**31.8**	32.6	32.2
Income tax expense	**48.0**	20.4	29.4
Income from continuing operations	**$ 77.5**	$ 40.0	$ 49.1
New well connects (A)	**206**	223	192
Gathered volumes TBtu/d (B)	**0.98**	0.92	0.84
Incremental transportation volumes TBtu/d	**0.46**	0.39	0.39
Total throughput volumes TBtu/d	**1.44**	1.31	1.23
Natural gas processed TBtu/d	**0.54**	0.52	0.50
Natural gas liquids sold (keep-whole) million gallons	**244**	219	185
Natural gas liquids sold (purchased for resale) million gallons	**113**	77	78
Natural gas liquids sold (percentage of liquids) million gallons	**14**	15	16
Total natural gas liquids sold million gallons	**371**	311	279
Average sales price per gallon	**$ 0.901**	$ 0.847	$ 0.720

(A) Excludes wells behind central receipt points.

(B) Trillion British thermal units per day.

2006 compared to 2005. Enogex s operating revenues and cost of goods sold decreased in 2006 approximately $2.0 billion, or 45.4 percent, and $2.0 billion, or 49.6 percent, respectively, as compared to 2005 primarily due to a lower level of trading activity due to a shift in strategy in Enogex s marketing business. Enogex s operating income increased approximately $49.2 million in 2006 as compared to 2005 primarily due to increased gross margins in each of Enogex s businesses largely as a result of higher commodity spreads and business growth in 2006 as compared to 2005. The increases in gross margin were partially offset by higher operating and maintenance expenses.

Transportation and storage contributed approximately $125.6 million of Enogex s gross margin in 2006 as compared to approximately $99.1 million in 2005, an increase of approximately $26.5 million or 26.7 percent. The gross margin increased primarily due to:

- better management of gas pipeline imbalances as Enogex reduced its exposure to gas imbalances while taking advantage of favorable market price movement in 2006 and gas imbalance expense recognized by the gathering business in 2006 (previously carried by the transportation and storage business in 2005), which increased the gross margin by approximately $11.5 million in 2006;
- increased commodity, interruptible and low and high pressure revenues primarily due to higher volumes, which increased the gross margin by approximately $6.2 million;
- a change in Enogex s 2005 accounting estimate of the volume of natural gas in its natural gas storage inventory, which reduced the 2005 gross margin by approximately $5.7 million;
- improved recovery of fuel as the Company transitioned to zonal fuel factors in 2006, which increased the gross margin by approximately $4.7 million;
- storage field hedging gains, which increased the gross margin by approximately $3.5 million; and
- increased natural gas sales due to higher realized natural gas prices in 2006, which increased the gross margin by approximately $3.5 million.

These increases in the transportation and storage gross margin were partially offset by a lower of cost or market adjustment related to natural gas inventory used to operate the pipeline during 2006, which reduced the 2006 gross margin by approximately $8.3 million as there was no comparable item during 2005.

Gathering and processing contributed approximately $167.6 million of Enogex s gross margin in 2006 as compared to approximately $140.2 million in 2005, an increase of approximately $27.4 million or 19.5 percent. The gathering and processing gross margin increased primarily due to:

- increased net keep-whole margins primarily due to higher commodity spreads in 2006 as compared to 2005 and increased volumes due to business growth, which increased the gross margin by approximately $33.5 million;
- contractual fuel gains primarily due to higher natural gas prices in 2006, which increased the gross margin by approximately $4.9 million; and
- a reduction in the Company s over recovered position as the Company transitioned to zonal fuel rates in 2006, which increased the gross margin by approximately $2.5 million.

These increases in the gathering and processing gross margin were partially offset by the recognition of imbalance expense in 2006 (previously carried by the transportation and storage business in 2005), which reduced the gross margin by approximately $13.8 million in 2006.

Marketing contributed approximately $14.2 million of Enogex s gross margin in 2006 as compared to approximately $2.7 million in 2005, an increase of approximately $11.5 million. The gross margin increased primarily due to:

- gains in storage activity due to timing, resulting from recording Enogex s storage hedges at market value at December 31, 2006 and an increase in storage capacity, which increased the gross margin by approximately $13.2 million;

- a correction to the accounting procedure for park and loan transactions (natural gas storage transactions) in the first quarter of 2005, which decreased the gross margin in the first quarter of 2005 by approximately $7.7 million (see Note 16 of Notes to Consolidated Financial Statements); and
- more favorable market conditions on transportation contracts, which increased the gross margin by approximately $7.6 million.

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

- a lower of cost or market adjustment related to natural gas in storage during 2006, which reduced the 2006 gross margin by approximately $9.9 million; and

- lower gains in trading and park and loan activity due to a lower level of activity in Enogex s marketing business and less favorable market conditions, which reduced the gross margin by approximately $6.0 million.

Enogex s other operating and maintenance expenses were approximately $110.0 million in 2006 as compared to approximately $96.6 million in 2005, an increase of approximately $13.4 million or 13.9 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages and other employee benefits of approximately $9.5 million primarily due to incentive compensation and hiring additional employees to support business growth; and
- higher materials and supplies costs of approximately $2.7 million primarily related to work performed to maintain the integrity and safety of Enogex s pipeline, higher cost of materials and increased materials used at newly added facilities.

These increases in other operating and maintenance expenses were partially offset by a sales and use tax refund of approximately $2.0 million received in May 2006 related to activity in prior years.

Depreciation expense was approximately $42.3 million in 2006 as compared to approximately $40.4 million during the same period in 2005, an increase of approximately $1.9 million or 4.7 percent, primarily due to new assets placed into service during 2006.

Interest income was approximately $11.1 million in 2006 as compared to approximately $2.9 million in 2005, an increase of approximately $8.2 million primarily due to interest income on cash investments from interest earned on the cash proceeds from the sale of EAPC in October 2005 and the sale of the Kinta Assets in May 2006.

Other income was approximately $7.7 million in 2006 as compared to approximately $0.8 million in 2005, an increase of approximately $6.9 million. The increase in other income was primarily due to:

- a litigation settlement of approximately $5.2 million (see Note 17 of Notes to Consolidated Financial Statements) in 2006;
- a gain of approximately $1.0 million in the fourth quarter of 2006 from the sale of certain west Texas pipeline asset segments; and
- a gain of approximately $0.5 million in the first quarter of 2006 from the sale of small gathering sections of Enogex s pipeline.

Income tax expense was approximately $48.0 million in 2006 as compared to approximately $20.4 million in 2005, an increase of approximately $27.6 million primarily due to higher pre-tax income for Enogex.

For 2006, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $113.5 million. During 2006, Enogex had an increase in net income of approximately $41.2 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex s business. These increases in net income include:

- a gain on the sale of the Kinta Assets in May 2006 of approximately $34.1 million;
- litigation settlement (see Note 17 of Notes to Consolidated Financial Statements) of approximately $3.2 million;

- income from discontinued operations of approximately $1.9 million;
- a sales and use tax refund related to activity in prior years of approximately $1.3 million;
- the sale of certain west Texas pipeline asset segments of approximately $0.6 million; and
- the sale of small gathering sections of Enogex s pipeline of approximately $0.3 million.

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

For 2005, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $89.8 million. During 2005, Enogex had an increase in net income of approximately $45.3 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex s business. These increases in net income include:

- a gain on the sale of EAPC in October 2005 of approximately $36.7 million;
- income from discontinued operations of approximately $11.3 million;
- a gain on the sale of Enerven in August 2005 of approximately $1.8 million; and
- income from a sales tax refund related to activity in prior years of approximately $0.2 million.

These increases to net income were partially offset by a correction to the accounting procedure for park and loan transactions in 2005 of approximately $4.7 million.

2005 compared to 2004. Enogex s operating income decreased approximately $13.7 million in 2005 as compared to 2004 primarily due to decreased gross margins in Enogex s marketing business and Enogex s transportation and storage business, which were partially offset by increased gross margins in Enogex s gathering and processing business. The overall decrease in gross margins was partially offset by an asset impairment charge of approximately $7.8 million recorded in 2004 with no similar item recorded in 2005.

Transportation and storage contributed approximately $99.1 million of Enogex s gross margin in 2005 as compared to approximately $114.5 million in 2004, a decrease of approximately $15.4 million or 13.4 percent. The gross margin decreased primarily due to:

- storage field gas losses, increased costs associated with natural gas purchases and sales, increased costs from electric compression, reduced fuel recoveries due to timing and system fuel volumes previously recorded in Enogex s transportation and storage business which are now being recorded in Enogex s gathering and processing business, which collectively reduced the gross margin by approximately $20.5 million; and
- reduced demand fees due to fewer overrun service charges with OG&E and the loss of firm contracts, which reduced the gross margin by approximately $2.1 million.

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

- increased crosshaul prices and volumes, which increased the gross margin by approximately $5.3 million; and
- increased commodity and interruptible revenues, which increased the gross margin by approximately $1.5 million.

Gathering and processing contributed approximately $140.2 million of Enogex s gross margin in 2005 as compared to approximately $123.4 million in 2004, an increase of approximately $16.8 million or 13.6 percent. The gathering and processing gross margin increased primarily due to:

- contractual fuel gains primarily due to higher natural gas prices and renegotiated contracts, which increased the gross margin by approximately $7.2 million;
- increased fuel over recoveries due to higher natural gas prices, 2005 fuel reserve and system fuel volumes previously recorded in Enogex s transportation and storage business which is now being recorded in Enogex s gathering and processing business, which increased the gross margin by approximately $6.2 million;
- increased condensate margins primarily due to higher condensate prices, which increased the gross margin by approximately $3.0 million;
- higher volumes related to compression and dehydration, which increased the gross margin by approximately $2.5 million;
- higher volumes on the low pressure gathering systems, which increased the gross margin by approximately $2.2 million;

- increased percent of liquids margins primarily due to higher natural gas prices, which increased the gross margin by approximately $1.4 million; and
- higher margin on natural gas sales reflective of opportunities in the marketplace, which increased the gross margin by approximately $1.1 million.

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

- decreased net keep-whole margins primarily due to higher natural gas prices, which reduced the gross margin by approximately $3.2 million;

- higher cost of electricity in 2005, which reduced the gross margin by approximately $3.0 million; and
- lower volumes on the high pressure gathering systems, which reduced the gross margin by approximately $1.0 million.

Marketing contributed approximately $2.7 million of Enogex s gross margin in 2005 as compared to approximately $23.8 million in 2004, a decrease of approximately $21.1 million or 88.7 percent. The gross margin decreased primarily due to:

- less favorable market conditions and trading activity, which reduced the gross margin by approximately $13.0 million;
- a correction to the accounting procedure for park and loan transactions (natural gas storage transactions) in the first quarter of 2005, which reduced the gross margin by approximately $7.7 million (see Note 16 of Notes to Consolidated Financial Statements); and
- losses incurred related to Enogex s position on the Cheyenne Plains transportation agreement, which reduced the gross margin by approximately $3.6 million.

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

- lower demand fees paid for storage services due to establishing new rates for the new storage season, which began April 1, 2004 which increased the gross margin by approximately $2.5 million; and
- gains in storage activity, which increased the gross margin by approximately $0.7 million.

Enogex s other operating and maintenance expenses were approximately $96.6 million in 2005 as compared to approximately $93.5 million in 2004, an increase of approximately $3.1 million or 3.3 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher outside service costs related to business development projects in 2005, system software implementation in 2005 and work performed to maintain the integrity and safety of Enogex s pipeline of approximately $4.4 million; and
- expenses related to a pipeline rupture in the second quarter 2005 of approximately $0.5 million.

These increases in other operating and maintenance expenses were partially offset by an uncollectible debt reserve of approximately $1.1 million recorded in 2004 with no similar reserve recorded in 2005.

Impairment of assets was approximately $7.8 million ($4.8 million after tax) in 2004 as a result of recording an impairment charge during the third quarter of 2004. The impairment charge related to certain Enogex natural gas pipeline assets that served a particular customer s power plants pursuant to a transportation agreement that was terminated by the customer effective December 31, 2004. There were no impairments recorded in 2005.

Interest income was approximately $2.9 million in 2005 as compared to approximately $3.2 million in 2004, a decrease of approximately $0.3 million or 9.4 percent, primarily due to a decrease in interest income of approximately $1.9 million due to the interest portion of an income tax refund related to prior periods which was received in 2004 with no similar activity recorded in 2005 partially offset by an increase in interest income of approximately $1.1 million from parent due to funds received from the sale of EAPC in October 2005.

Other income was approximately $0.8 million in 2005 as compared to approximately $4.5 million in 2004, a decrease of approximately $3.7 million or 82.2 percent. The decrease in other income was primarily due to a gain in 2004 of approximately $3.0 million from the sale of certain of Enogex s compression and processing assets in 2004 in addition to approximately $0.8 million received related to a bankruptcy settlement from one of Enogex s customers during the third quarter of 2004.

Income tax expense was approximately $20.4 million in 2005 as compared to approximately $29.4 million in 2004, a decrease of approximately $9.0 million or 30.6 percent. The decrease in income tax expense was primarily due to:

- lower pre-tax income for Enogex; and
- a reduction in excess deferred taxes of approximately $3.2 million in 2005.

These decreases in income tax expense were partially offset by a decrease in Oklahoma state income tax credits of approximately $1.6 million in 2005 as compared to 2004.

For 2005, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $89.8 million. During 2005, Enogex had an increase in net income of approximately $45.3 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex s business. These increases in net income include:

- a gain on the sale of EAPC in October 2005 of approximately $36.7 million;
- income from discontinued operations of approximately $11.3 million;
- a gain on the sale of Enerven in August 2005 of approximately $1.8 million; and
- income from a sales tax refund related to activity in prior years of approximately $0.2 million.

These increases to net income were partially offset by a correction to the accounting procedure for park and loan transactions in 2005 of approximately $4.7 million.

For 2004, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $60.7 million. During 2004, Enogex had an increase in net income of approximately $15.6 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex s business. These increases in net income include:

- income from discontinued operations of approximately $11.7 million;
- authorized recovery of previously under recovered fuel of approximately $3.8 million;
- a gain on the sale of Enogex compression and processing assets of approximately $1.8 million;
- an imbalance settlement with a customer of approximately $1.6 million;
- a net Oklahoma investment tax credit of approximately $1.0 million; and
- a settlement related to a customer bankruptcy of approximately $0.5 million.

These increases to net income were partially offset by a net impairment charge of approximately $4.8 million.

Enogex Discontinued Operations

In April 2005, Enogex Compression Company, LLC (Enogex Compression) received an unsolicited offer to buy its interest in Enerven, a joint venture focused on the rental of natural gas compression assets. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business.

Enogex regularly evaluates the long term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on these evaluations, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in EAPC, which held a 75 percent interest in the NOARK Pipeline System Limited Partnership. This sale was completed on October 31, 2005. The Company received approximately $177.4 million in cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter of 2005. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million, was used, among other things, to reduce short-term debt levels and fund capital expenditures.

In March 2006, Enogex announced that its wholly-owned subsidiary, Gathering, had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction were approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and Enogex recorded an after tax gain of approximately $34.1 million during the second quarter of 2006. The proceeds from the sale, were used, among other things, to reduce short-term debt levels and fund capital expenditures.

As a result of these sale transactions, Enogex Compression s interest in Enerven, Enogex s interest in EAPC and Gathering s Kinta Assets, which were part of the Natural Gas Pipeline segment, have been reported as discontinued operations for the years ended December 31, 2006, 2005 and 2004 in the Consolidated Financial Statements. Enogex Compression s sale of its Enerven interest and Enogex s sale of its EAPC interest were completed during 2005 and, therefore, there are no results of operations for these transactions during 2006. Results for these discontinued operations are summarized and discussed below.

Year ended December 31 *(In millions)*	**2006**	2005	2004
Operating revenues	**$ 9.4**	$ 106.0	$ 120.1
Cost of goods sold	**4.9**	69.5	80.0
Gross margin on revenues	**4.5**	36.5	40.1
Other operation and maintenance	**1.0**	7.5	7.9
Depreciation	**0.3**	5.8	6.5
Taxes other than income	**0.1**	1.3	1.5
Operating income	**3.1**	21.9	24.2
Interest income	**---**	0.1	0.3
Other income	**56.0**	66.2	---
Other expense	**---**	0.2	0.6
Interest expense	**---**	4.0	5.3
Income tax expense	**23.1**	34.4	7.0
Net income	**$ 36.0**	$ 49.8	$ 11.6

2006 compared to 2005. Gross margin decreased approximately $32.0 million or 87.7 percent in 2006 as compared to 2005 primarily due to the sale of EAPC in October 2005, the sale of the Kinta Assets in May 2006 and a decrease in natural gas purchases and sales due to a decrease in natural gas transported prior to these assets being sold.

Operating and maintenance expense decreased approximately $6.5 million or 86.7 percent in 2006 as compared to 2005 primarily due to the sale of EAPC in October 2005 and the sale of the Kinta Assets in May 2006.

Depreciation expense decreased approximately $5.5 million or 94.8 percent in 2006 as compared to 2005 primarily due to the sale of EAPC in October 2005 and ceasing depreciation expense in January 2006 when the Kinta Assets were reported as a discontinued operation.

Taxes other than income decreased approximately $1.2 million or 92.3 percent in 2006 as compared to 2005 for ad valorem taxes primarily due to the sale of EAPC in October 2005.

Other income decreased approximately $10.2 million or 15.4 percent in 2006 as compared to 2005 due to the sale of the Kinta Assets in May 2006 partially offset by the sale of EAPC in October 2005 and the sale of Enerven in August 2005.

Interest expense decreased approximately $4.0 million or 100.0 percent in 2006 as compared to 2005 due to the sale of EAPC in October 2005 and the use of a portion of the sale proceeds to repay EAPC long-term debt.

Income tax expense increased approximately $11.3 million or 32.8 percent in 2006 as compared to 2005 primarily due to the sale of the Kinta Assets in May 2006 partially offset by the sale of EAPC in October 2005 and the sale of Enerven in August 2005.

2005 compared to 2004. Gross margin decreased approximately $3.6 million or 9.0 percent in 2005 as compared to 2004 primarily due to the sale of EAPC in October 2005 and a decrease in natural gas purchases and sales due to a decrease in natural gas transported prior to these assets being sold.

Other income increased approximately $66.2 million in 2005 as compared to 2004 due to a pre-tax gain of approximately $83.4 million recognized in the fourth quarter of 2005 related to the sale of EAPC and a pre-tax gain of approximately $2.9 million recognized in the third quarter of 2005 related to the sale of Enerven.

Interest expense decreased approximately $1.3 million or 24.5 percent in 2005 as compared to 2004 due to the sale of EAPC in October 2005 and the use of a portion of the sale proceeds to repay EAPC long-term debt.

Income tax expense increased approximately $27.4 million in 2005 as compared to 2004 primarily due to the sale of the Kinta Assets in May 2006 partially offset by the sale of EAPC in October 2005 and the sale of Enerven in August 2005.

Financial Condition

The balance of Cash and Cash Equivalents was approximately $47.9 million and $26.4 million at December 31, 2006 and 2005, respectively, an increase of approximately $21.5 million or 81.4 percent, primarily due to proceeds received in October 2006 from the sale of Gathering s Kinta Assets in May 2006.

The balance of Funds on Deposit was approximately $32.0 million at December 31, 2006 due to the Company making a deposit with the IRS on August 17, 2006 in anticipation that a portion of prior year deductions will be disallowed. The deposit enabled the Company to cease accruing interest effective August 17, 2006. See Note 10 of Notes to Consolidated Financial Statements for a further discussion.

The balance of Accounts Receivable, Net was approximately $344.3 million and $591.4 million at December 31, 2006 and 2005, respectively, a decrease of approximately $247.1 million or 41.8 percent, primarily due to lower natural gas sales prices and volumes by Enogex, a decrease in OG&E s billings to its customers reflecting lower fuel costs in December 2006 as compared to December 2005 and payments received from other utilities for OG&E s assistance with hurricanes Katrina and Rita.

The balance of current Price Risk Management assets was approximately $41.9 million and $116.5 million at December 31, 2006 and 2005, respectively, a decrease of approximately $74.6 million or 64.0 percent. The decrease was primarily due to lower natural gas prices associated with OGE Energy Resources, Inc. (OERI) short-term physical natural gas purchase transactions and associated financial contracts. A reduction in the volume of OERI s short-term physical natural gas activity and associated financial contracts outstanding at December 31, 2006 from December 31, 2005 also contributed to the decrease.

The balance of Gas Imbalance asset was approximately $2.8 million and $32.0 million at December 31, 2006 and 2005, respectively, a decrease of approximately $29.2 million or 91.3 percent. The Gas Imbalance asset is comprised of planned or managed imbalances related to OERI s business, referred to as park and loan transactions, and pipeline and natural gas liquids imbalances, which are operational imbalances. Park and loan transactions were approximately $15.7 million at December 31, 2005 with no comparable balance at December 31, 2006. The decrease in park and loan transactions was due to the expiration of 2005 park and loan transactions in OERI s business activities. Operational imbalances were approximately $2.8 million and $16.3 million at December 31, 2006 and 2005, respectively, a decrease of approximately $13.5 million or 82.8 percent. The decrease in operational imbalances was primarily due to Enogex beginning to manage imbalances related to its storage operations on a combined basis in 2006 for its two storage facilities which resulted in a decrease in net imbalance volumes.

The balance of Construction Work in Progress was approximately $191.1 million and $101.8 million at December 31, 2006 and 2005, respectively, an increase of approximately $89.3 million or 87.7 percent, primarily due to construction expenditures related to OG&E s Centennial wind farm in addition to construction expenditures related to the expansion of Enogex s gathering pipeline capacity on the west side of its system in western Oklahoma and the Texas Panhandle.

The balance of Regulatory Asset SFAS 158 was approximately $231.1 million at December 31, 2006 with no comparable balance at December 31, 2005. The balance of Intangible Asset Unamortized Prior Service Cost was approximately $32.8 million at December 31, 2005 with no comparable balance at December 31, 2006. The balance of Prepaid Benefit Obligation was approximately $90.2 million at December 31, 2005 with no comparable balance at December 31, 2006. The change in these balances is due to the accounting change required upon adoption of SFAS No. 158, effective December 31, 2006, which required the Company to record the funded status of its pension and postretirement benefit plans on the Consolidated Balance Sheet (see Notes 1 and 2 of Notes to Consolidated Financial Statements for a further discussion).

The balance of Deferred Charges Other was approximately $23.1 million and $7.2 million at December 31, 2006 and 2005, respectively, an increase of approximately $15.9 million, primarily due to the creation of a regulatory asset at OG&E of approximately $14.7 million for the excess pension expense over the amount granted in rates by the OCC in OG&E s last Oklahoma rate case (see Note 1 of Notes to Consolidated Financial Statements for further discussion).

The balance of Short-Term Debt was approximately $30.0 million at December 31, 2005 with no comparable balance at December 31, 2006. The decrease was primarily due to proceeds received in October 2006 from the sale of Gathering s Kinta Assets in May 2006 which were used to pay down the commercial paper balance.

The balance of Accounts Payable was approximately $295.0 million and $510.4 million at December 31, 2006 and 2005, respectively, a decrease of approximately $215.4 million or 42.2 percent, primarily due to lower natural gas prices and volumes in December 2006 as compared to December 2005 and the timing of outstanding checks clearing the bank.

The balance of current Price Risk Management liabilities was approximately $9.2 million and $109.5 million at December 31, 2006 and 2005, respectively, a decrease of approximately $100.3 million or 91.6 percent. The decrease was primarily due to lower natural gas prices associated with OERI s short-term physical natural gas purchase transactions and associated financial contracts. A reduction in the volume of OERI s short-term physical natural gas activity and associated financial contracts outstanding at December 31, 2006 from December 31, 2005 also contributed to the decrease.

The balance of Gas Imbalance liability was approximately $11.1 million and $36.0 million at December 31, 2006 and 2005, respectively, a decrease of approximately $24.9 million or 69.2 percent. The Gas Imbalance liability is comprised of planned or managed imbalances related to OERI s business, referred to as park and loan transactions, and pipeline and natural gas liquids imbalances, which are operational imbalances. Park and loan transactions were approximately $10.2 million at December 31, 2005 with no comparable balance at December 31, 2006. The decrease in park and loan transactions was due to the expiration of 2005 park and loan transactions in OERI s business activities. Operational imbalances were approximately $11.1 million and $25.8 million at December 31, 2006 and 2005, respectively, a decrease of approximately $14.7 million or 57.0 percent. The decrease in operational imbalances was primarily due to Enogex beginning to manage imbalances related to its storage operations on a combined basis in 2006 for its two storage facilities which resulted in a decrease in net imbalance volumes.

The balance of Fuel Clause Over Recoveries was approximately $96.3 million at December 31, 2006. The balance of Fuel Clause Under Recoveries was approximately $101.1 million at December 31, 2005. The increase in fuel clause over recoveries was due to the amount billed to OG&E s customers during 2006 exceeding OG&E s cost of fuel due to lower than expected natural gas prices and amounts recovered under approved tariffs exceeding the amounts intended by the December 2005 OCC rate order. OG&E s fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers bills. As a result, OG&E typically under recovers fuel cost in periods of rising prices above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under or over recovery. As described in more detail in Note 18 of Notes to Consolidated Financial Statements, the OCC, in its order dated December 12, 2005, granted OG&E a $42.3 million annual increase in the rates charged by OG&E to its retail customers in Oklahoma. These increased rates became effective in January 2006 pursuant to approved tariffs filed with the OCC. In January 2007, OG&E determined that the approved tariffs had inadvertently authorized OG&E to collect, and OG&E had collected, approximately $26.7 million of additional fuel-related revenues during 2006 that was not intended by the December 12, 2005 order. As a result, OG&E filed with the OCC in January 2007 amendments to its previously-authorized tariffs, in order to cease recovery of the fuel-related revenues not intended by the December 12, 2005 order. The $26.7 million, plus $1.2 million of interest, was recorded as a liability under Fuel Clause Over Recoveries on the Consolidated Balance Sheet in the fourth quarter of 2006, and such amounts, along with other Fuel Clause Over Recoveries, will be credited to OG&E s Oklahoma customers in 2007 and 2008 through OG&E s automatic fuel adjustment clause. In addition, OG&E recorded a reduction in operating revenues of approximately $26.7 million and an increase in interest expense of approximately $0.5 million, which resulted in an after tax reduction in net income of approximately $16.7 million in the fourth quarter of 2006. Because the rate increase authorized in the December 2005 order was not implemented until January 2006 and the tariffs were corrected effective December 31, 2006, the $26.7 million had no impact on net income for the year ended December 31, 2006. See additional discussion in Supplementary Data Interim Consolidated Financial Information (Unaudited).

Off-Balance Sheet Arrangements

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

Bulletin No. 51,   in an unconsolidated entity that is held by, and material to, the Company, where such entity provides financing, liquidity, market risk or credit risk support to, or engages in leasing,

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hedging or research and development services with, the Company. The Company has the following material off-balance sheet arrangements.

OG&E Railcar Lease Agreement

OG&E leases more than 1,400 railcars used to deliver coal to OG&E s coal-fired generation units. See Note 17 of Notes to Consolidated Financial Statements for a discussion of OG&E s railcar lease agreement.

Liquidity and Capital Requirements

The Company s primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and at Enogex. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage, delays in recovering unconditional fuel purchase obligations and fuel clause under and over recoveries. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings.

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

(In millions)	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
OG&E capital expenditures including AFUDC (A)	$ 3,297.3	$ 426.5	$ 1,434.7	$ 1,070.1	$ 366.0
Enogex capital expenditures including capitalized interest	504.6	124.8	199.8	120.0	60.0
Other Operations capital expenditures	66.8	16.8	20.0	20.0	10.0
Total capital expenditures	3,868.7	568.1	1,654.5	1,210.1	436.0
Maturities of long-term debt	1,249.4	3.0	1.0	400.0	845.4
Interest payments on long-term debt	1,068.5	80.6	160.7	98.8	728.4
Pension funding obligations	129.7	50.0	46.1	33.6	N/A
Total capital requirements	6,316.3	701.7	1,862.3	1,742.5	2,009.8
Operating lease obligations					
OG&E railcars	52.0	4.0	7.7	40.3	---
Enogex noncancellable operating leases	8.6	2.2	3.1	2.9	0.4
Total operating lease obligations	60.6	6.2	10.8	43.2	0.4
Other purchase obligations and commitments					
OG&E cogeneration capacity payments	471.3	97.6	190.5	183.2	N/A
OG&E fuel minimum purchase commitments	614.5	198.0	220.0	173.1	23.4
Other	56.3	6.9	13.8	13.8	21.8
Total other purchase obligations and commitments	1,142.1	302.5	424.3	370.1	45.2
Total capital requirements, operating lease obligations and other purchase obligations and commitments	7,519.0	1,010.4	2,297.4	2,155.8	2,055.4
Amounts recoverable through automatic fuel adjustment clause (B)	(1,137.8)	(299.6)	(418.2)	(396.6)	(23.4)
Total, net	$ 6,381.2	$ 710.8	$ 1,879.2	$ 1,759.2	$ 2,032.0

(A) Under current environmental laws and regulations, OG&E may be required to spend approximately $600 million in capital expenditures on its coal-fired plants. These expenditures are expected to begin in 2007 and would continue over the next five years.

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

N/A not available

Variances in the actual cost of fuel used in electric generation (which includes the operating lease obligations for OG&E s railcar leases shown above) and certain purchased power costs, as compared to the fuel component included in the

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cost-of-service for ratemaking, are passed through to OG&E s customers through automatic fuel adjustment clauses. Accordingly, while the cost of fuel related to operating leases and the vast majority of unconditional fuel purchase obligations of OG&E noted above may increase capital requirements, such costs are recoverable through automatic fuel adjustment clauses and have little, if any, impact on net capital requirements and future contractual obligations. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. See Note 18 of Notes to Consolidated Financial Statements for a discussion of the completed proceedings at the OCC regarding OG&E s gas transportation and storage contract with Enogex.

2006 Capital Requirements and Financing Activities

Total capital requirements, consisting of capital expenditures, maturities of long-term debt, interest payments on long-term debt and pension funding obligations, were approximately $662.1 million and contractual obligations, net of recoveries through automatic fuel adjustment clauses, were approximately $10.7 million resulting in total net capital requirements and contractual obligations of approximately $672.9 million in 2006. Approximately $17.8 million of the 2006 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $448.8 million and net contractual obligations of approximately $4.3 million totaling approximately $453.1 million in 2005, of which approximately $19.2 million was to comply with environmental regulations. During 2006, the Company s sources of capital were internally generated funds from operating cash flows, short-term borrowings (through a combination of bank borrowings and commercial paper) and proceeds from the sale of assets. The Company uses its commercial paper to fund changes in working capital and as an interim source of financing capital expenditures until permanent financing is arranged. Changes in working capital reflect the seasonal nature of the Company s business, the revenue lag between billing and collection from customers and fuel inventories. See Financial Condition for a discussion of significant changes in net working capital requirements as it pertains to operating cash flow and liquidity.

Discontinued Operations

Also contributing to the liquidity of the Company has been the disposition of certain assets classified as discontinued operations in 2005 and 2006. During 2005 and 2006, these dispositions have generated net sales proceeds of approximately $277.6 million. Sales proceeds generated to date have been used to reduce short-term debt levels and fund capital expenditures.

Additional asset sales could further contribute to the liquidity of the Company.

Long-term Debt Maturities

Maturities of the Company s long-term debt during the next five years consist of $3.0 million in 2007; $1.0 million in 2008 and $400.0 million in 2010. There are no maturities of the Company s long-term debt in years 2009 or 2011.

Future Capital Requirements

Capital Expenditures

The Company s current 2007 to 2012 construction program includes continued investment in OG&E s distribution, generation and transmission system and Enogex s pipeline assets. The Company s current estimates of capital expenditures for 2007 through 2012 are approximately $568.1 million, $838.6 million, $815.9 million, $659.9 million, $550.2 million and $436.0 million, respectively, which include capital expenditures of approximately $94.0 million, $278.8 million, $285.7 million, $97.7 million and $34.1 million, respectively, in 2007 through 2011 related to the construction of the Red Rock power plant. OG&E also has approximately 550 MW s of contracts with qualified cogeneration facilities (QF) and small power production producers (QF contracts) to meet its current and future expected customer needs. OG&E will continue reviewing all of the supply alternatives to these QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates.

Pension and Postretirement Benefit Plans

During 2006, actual asset returns for the Company s defined benefit pension plan were positively affected by growth in the equity markets. At December 31, 2006, approximately 64 percent of the pension plan assets are invested in listed common stocks with the balance invested in corporate debt and U.S. Government securities. In 2006, asset returns on the pension plan were approximately 14.5 percent as compared to approximately 6.2 percent in 2005. During the same time,

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corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline.

Contributions to the pension plan increased from approximately $32.0 million in 2005 to approximately $90.0 million in 2006. This increase in pension plan contributions in 2006 was to maintain an adequate funded status. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and increases in discount rates will reduce funding requirements to the plan. In August 2006, legislation was passed that changed the funding requirement for single- and multi-employer defined benefit pension plans as discussed below. During 2007, the Company may contribute up to $50 million to its pension plan.

In accordance with Statement of Financial Accounting Standard (SFAS) No. 88, Employer s Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization s net periodic pension cost. During 2006, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments to be paid to such employees upon retirement in 2006. As a result, the Company recorded a pension settlement charge for 2006 of approximately $17.1 million in the fourth quarter of 2006. The pension settlement charge did not require a cash outlay by the Company and did not increase the Company s total pension expense over time, as the charge was an acceleration of costs that otherwise would have been recognized as pension expense in future periods. OG&E s Oklahoma jurisdictional portion of this charge was recorded as a regulatory asset (see Note 1 of Notes to Consolidated Financial Statements for a further discussion).

As discussed in Note 15 of Notes to Consolidated Financial Statements, in 2000 the Company made several changes to its pension plan, including the adoption of a cash balance benefit feature for employees hired after January 31, 2000. The cash balance plan may provide lower post-employment pension benefits to employees, which could result in less pension expense being recorded. Over the near term, the Company s cash requirements for the plan are not expected to be materially different than the requirements existing prior to the plan changes. However, as the population of employees included in the cash balance plan feature increases, the Company s cash requirements should decrease and will be much less sensitive to changes in discount rates.

At December 31, 2006, the projected benefit obligation and fair value of assets of the Company s pension plan and restoration of retirement income plan was approximately $585.0 million and $519.4 million, respectively, for an underfunded status of approximately $65.6 million. Also, at December 31, 2006, the accumulated postretirement benefit obligation and fair value of assets of the Company s postretirement benefit plans was approximately $225.4 million and $74.0 million, respectively, for an underfunded status of approximately $151.4 million. The above amounts have been recorded in Accrued Pension and 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 entry did not impact the results of operations in 2006 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic pension cost to be recognized in the Consolidated Statements of Income in future periods.

During 2005, the Company made contributions to the pension plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2005 of approximately $88.9 million. At December 31, 2005, the Company s projected pension benefit obligation exceeded the fair value of the pension plan assets by approximately $154.6 million. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87 required the recognition of an additional minimum liability in the amount of approximately $181.4 million at December 31, 2005. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2005 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amount recorded as an intangible asset equaled the unrecognized prior service cost with the remainder recorded in Accumulated Other Comprehensive Income. The amount in Accumulated Other Comprehensive Income represents a net periodic pension cost to be recognized in the Consolidated Statements of Income in future periods.

Pension Plan Costs and Assumptions

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the Pension Protection Act) into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Among other things, it

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introduces a new funding requirement for single- and multi-employer defined benefit pension plans, provides legal certainty on a prospective basis for cash balance and other hybrid plans and addresses contributions to defined contribution plans, deduction limits for contributions to retirement plans and investment advice provided to plan participants. The Company is currently analyzing the impact of the Pension Protection Act on its pension plans. Long-Term Debt with Optional Redemption Provisions

OG&E s $125.0 million principal amount 6.65 percent Senior Notes (Senior Notes) due July 15, 2027, are repayable on July 15, 2007, at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to July 15, 2007. Only holders who submit requests for repayment between May 15, 2007 and June 15, 2007 are entitled to such repayments. In accordance with SFAS No. 6, Classification of Short-Term Obligations Expected to Be Refinanced, OG&E reclassified the Senior Notes from long-term debt due within one year to long-term debt at December 31, 2006 due to OG&E having sufficient long-term liquidity in place as a result of increasing its revolving credit agreement to $400.0 million in December 2006. Also, based on where the Senior Notes have recently traded, OG&E does not believe it is probable that this option will be exercised by the note holders.

SPP Letter of Credit

On October 31, 2006, OG&E submitted a commercial letter of credit to the Southwest Power Pool for approximately $2.9 million related to the costs of upgrades required for OG&E to obtain transmission service from its new Centennial wind farm. This commercial letter of credit is not recorded as a liability on the Company s Consolidated Balance Sheet.

Security Ratings

	Moody s	Standard & Poor s	Fitch s
OG&E Senior Notes	A2	BBB+	AA-
Enogex Notes	Baa3	BBB+	BBB
OGE Energy Corp. Senior Notes	Baa1	BBB	A
OGE Energy Corp. Commercial Paper	P2	A2	F1

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

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

Future Sources of Financing

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

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. In December 2006, the Company and OG&E increased their aggregate available borrowing capacity under their revolving credit agreements from $750.0 million to $1.0 billion, $600 million for the Company and $400 million for OG&E. Also, OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any time for a two-year period beginning January 1, 2007 and ending December 31, 2008. See Note 14 of Notes to Consolidated Financial Statements for a discussion of the Company s short-term debt activity.

Common Stock

See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company s common stock activity.

Critical Accounting Policies and Estimates

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

Consolidated (including Electric Utility and Natural Gas Pipeline Segments)

Pension and Postretirement Benefit Plans

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 15 of Notes to Consolidated Financial Statements. The assumed return on plan assets is based on management s expectation of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and an increase in discount rates will reduce funding requirements to the pension plan. The following table indicates the sensitivity of the pension plan funded status to these variables.

	Change	Impact on Funded Status
Actual plan asset returns	+/- 5 percent	+/- $26.0 million
Discount rate	+/-0.25 percent	+/- $19.5 million
Contributions	+ $10.0 million	+ $10.0 million
Expected long-term return on plan assets	+/- 1 percent	None

Impairment of Assets

The Company assesses potential impairments of assets or asset groups when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset or asset group. For purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Estimates of future cash flows used to test the recoverability of a long-lived asset or asset group shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset or asset group. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flow. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets have not been included in the 2007 earnings guidance.

Commitments and Contingencies

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

Asset Retirement Obligations

In accordance with FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations, an entity was required to recognize a liability for the fair value of an asset retirement obligation (ARO) that was conditional on a future event if the liability s fair value could be reasonably estimated. The fair value of a liability for the conditional ARO was recognized when incurred. Uncertainty surrounding the timing and method of settlement of a conditional ARO was factored into the measurement of the liability when sufficient information existed. However, in some cases, there was insufficient information to estimate the fair value of an ARO. In these cases, the liability was initially recognized in the period in which sufficient information was available for an entity to make a reasonable estimate of the liability s fair value. In the fourth quarter of 2006, OG&E recorded an ARO for approximately $0.9 million related to its Centennial wind farm. Beginning January 1, 2007, the Company will amortize the remaining value of the related ARO asset over the estimated remaining life of 99 years. The Company has also identified other ARO s that have not been recorded because the Company determined that these assets have indefinite lives primarily related to Enogex s processing plants and compression sites.

Hedging Policies

Enogex engages in cash flow hedge transactions to manage commodity risk. Enogex may hedge its forward exposure to manage changes in commodity prices. Anticipated transactions are documented as cash flow hedges pursuant to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, hedging requirements and are executed based upon management established price targets. During 2004 and 2005, Enogex and OERI utilized hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas and certain types of natural gas liquid hedges. During 2006, Enogex and OERI utilized hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas, natural gas liquid hedges and certain transportation hedges. Hedges are evaluated prior to execution with respect to the impact on the volatility of forecasted earnings and are evaluated at least quarterly after execution for the impact on earnings. OG&E and Enogex engage in cash flow and fair value hedge transactions to modify the rate composition of the debt portfolio. During 2004, OG&E and Enogex entered into interest rate swap agreements and, during 2005 and 2006, OG&E entered into treasury lock agreements relating to managing interest rate exposure on the debt portfolio or anticipated debt issuances to modify the interest rate exposure on fixed rate debt issues. These interest rate swaps and treasury lock agreements qualified as fair value or cash flow hedges under SFAS No. 133. The objective of the interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. The objective of the treasury lock agreements in late 2005 was to protect against the variability of future payments of interest expense of debt that was issued by OG&E in January 2006 and the objective of the treasury lock agreement in November 2006 is to protect against the variability of future interest payments of long-term debt that is expected to be issued during the first half of 2007.

Electric Utility Segment

Regulatory Assets and Liabilities

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

OG&E records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates. The Company adopted certain provisions of SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R, effective December 31, 2006, which requires the Company to separately disclose the items that have not yet been recognized as components of net periodic pension cost including, net loss, prior service cost and net transition obligation at December 31, 2006. For companies not subject to SFAS No. 71, SFAS No. 158 required this information to be included in

Accumulated Other Comprehensive Income. However, for companies subject to SFAS No. 71, this information is allowed to be recorded as a regulatory asset if: (i) the utility has historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates; and (ii) there is no negative evidence that the existing regulatory treatment will change. Therefore, OG&E has recorded the net loss, prior service cost and net transition obligation as a regulatory asset as these expenses are probable of future recovery. If, in the future, the regulatory bodies indicated a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the SFAS No. 158 regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

Unbilled Revenues

OG&E reads its customers meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. At December 31, 2006, if the estimated usage or price used in the unbilled revenue calculation were to increase or decrease by one percent, this would cause a change in the unbilled revenues recognized of approximately $0.2 million. At December 31, 2006 and 2005, Accrued Unbilled Revenues were approximately $39.7 million and $41.8 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. At December 31, 2006, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of approximately $0.3 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable, Net on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was approximately $3.3 million and $2.5 million at December 31, 2006 and 2005, respectively.

Natural Gas Pipeline Segment

Operating Revenues

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

Natural Gas Purchases

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

Energy Purchase and Sale Contracts

OERI s activities include the marketing of natural gas and natural gas liquids. The vast majority of these contracts expire within three years, which is when the cash aspect of the transactions will be realized. A substantial portion of these contracts qualify as derivatives under SFAS No. 133 and are marked-to-market with offsetting gains and losses recorded in earnings. In nearly all cases, independent market prices are obtained and compared to the values used for this mark-to-market valuation, and an oversight group outside of the marketing organization monitors all modeling methodologies and assumptions. The recorded value of the energy contracts may change significantly in the future as the market price for the commodity changes, but the value is still subject to the risk loss limitations provided under the Company s risk policies. The

Company utilizes models to estimate the fair value of its energy contracts including derivatives that do not have an independent market price. At December 31, 2006, unrealized mark-to-market gains were approximately $31.2 million, which included approximately $0.5 million of unrealized mark-to-market gains that were calculated utilizing models. At December 31, 2006, a price movement of one percent for prices verified by independent parties would result in changes in unrealized mark-to-market gains of less than $0.1 million and a price movement of five percent on model-based prices would result in changes in unrealized mark-to-market gains of approximately $0.1 million. Energy contracts are presented in Price Risk Management assets, liabilities or against the brokerage deposits in Other Current Assets on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income.

Natural Gas Inventory

Natural gas inventory is held by Enogex Inc. and OERI. Enogex Inc. maintains of natural gas inventory to provide operational support for its pipeline deliveries. As part of its recurring business activity, OERI injects and withdraws natural gas in to and out of inventory under the terms of its storage capacity contracts. In order to mitigate market price exposures, OERI enters into contracts or hedging instruments to protect the cash flows associated with its inventory. OERI has elected not to designate inventory hedging contracts as fair value or cash flow hedges under SFAS No. 133. The fair value of the hedging instruments is recorded on the books of OERI as Price Risk Management assets, liabilities or against the brokerage deposits in Other Current Assets with an offsetting gain or loss recorded in current earnings. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2006, Enogex recorded write-downs to market value related to natural gas storage inventory of approximately $18.7 million. The amount of Enogex s natural gas inventory was approximately $35.9 million and $35.7 million at December 31, 2006 and 2005, respectively. Natural gas storage inventory is presented in Fuel Inventories on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

Allowance for Uncollectible Accounts Receivable

The allowance for uncollectible accounts receivable is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when the Company believes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable, Net 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 for the Natural Gas Pipeline segment was approximately $1.1 million and $1.2 million at December 31, 2006 and 2005, respectively.

Accounting Pronouncements

See Notes 2 and 3 of Notes to Consolidated Financial Statements for a discussion of recent accounting pronouncements that are applicable to the Company.

Electric Competition; Regulation

OG&E and Enogex have been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although retail restructuring efforts in Oklahoma and Arkansas 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 the Company due to an impairment of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. Any such restructuring also could have a significant impact on the Company s consolidated financial position, results of operations and cash flows. The Company cannot predict when it will be subject to changes in legislation or regulation, nor can it predict the impact of these changes on the Company s consolidated financial position, results of operations or cash flows. The Company believes that the prices for electricity and the quality and reliability of the Company s service currently place us in a position to compete effectively in the energy market. These developments at the federal and state levels are described in more detail in Note 18 of Notes to Consolidated Financial Statements. OG&E is also subject to competition in various degrees from state-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators. OG&E has a franchise to serve in more than 270 towns and cities throughout its service territory. In a citywide election in May 2006, Oklahoma City voters approved a 25-year franchise for OG&E which is the largest city in OG&E s service territory.

Commitments and Contingencies

Except as disclosed otherwise in this Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company s consolidated financial position, results of operations or cash flows. See Notes 17 and 18 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.

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 commodity prices, commodity price volatilities and interest rates. The Company is exposed to commodity price and commodity price volatility risks in its operations. The Company s exposure to changes in interest rates relates primarily to short-term variable-rate debt, interest rate swap agreements, treasury lock agreements and commercial paper. The Company also engages in price risk management activities for both trading and non-trading purposes.

Risk Committees and Oversight

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

The Unregulated Business Unit Risk Management Committee is comprised primarily of business unit leaders within Enogex. 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 our Chief Risk and Compliance Officer. This group, in conjunction with the aforementioned committees, is responsible for establishing and enforcing the Company s risk policies.

Risk Policies

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

Interest Rate Risk

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

Cash Flow Hedge of Interest Rates

OG&E entered into a treasury lock agreement, effective November 17, 2006, to hedge interest payments on the first $50.0 million of long-term debt that is expected to be issued during the first half of 2007. This treasury lock expires March 29, 2007.

The fair value of the Company s long-term debt is based on quoted market prices and management s estimate of current rates available for similar issues with similar maturities. At December 31, 2006, the Company had no outstanding interest rate swap agreements. The following table shows the Company s long-term debt maturities and the weighted-average interest rates by maturity date.

Year ended December 31 *(Dollars in millions)*	2007	2008	2009	2010	2011	Thereafter	Total	12/31/06 Fair Value
Fixed-rate debt (A)								
Principal amount	$ 3.0	$ 1.0	$ ---	$400.0	$ ---	$ 810.0	$ 1,214.0	$ 1,254.2
Weighted-average interest rate	8.28%	7.07%	---	8.13%	---	6.05%	6.74%	---
Variable-rate debt (B)								
Principal amount	---	---	---	---	---	$ 135.4	$ 135.4	$ 135.4
Weighted-average interest rate	---	---	---	---	---	3.56%	3.56%	---

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

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

The Company s price risk management assets and liabilities as of December 31, 2006 were as follows:

December 31 *(In millions)*	Commodity	Notional Volume (MMBtu)	Maturity	Fair Value
TRADING				
Price Risk Management Assets				
Physical Purchases	Natural Gas	12.4	2007	$ 1.4
Physical Purchases	Natural Gas	1.5	2008	0.3
Total Physical Purchases				1.7
Physical Sales	Natural Gas	24.7	2007	28.1
Short Physical Options	Natural Gas	39.9	2007	2.7
Short Financial Swaps (excluding basis)	Natural Gas	0.4	2007	1.1
Long Basis Positions	Natural Gas	15.0	2007	7.6
Long Basis Positions	Natural Gas	2.8	2008	1.1
Long Basis Positions	Natural Gas	0.9	2009	0.2
Total Long Basis Positions				8.9
Short Basis Positions	Natural Gas	1.2	2007	0.1
Total Trading Price Risk Management Assets				$ 42.6
TRADING				
Price Risk Management Liabilities				
Physical Purchases	Natural Gas	19.1	2007	$ 1.7
Physical Purchases	Natural Gas	0.5	2008	0.3
Total Physical Purchases				2.0
Physical Sales	Natural Gas	9.1	2007	1.6
Long Physical Options	Natural Gas	1.5	2007	1.0
Long Financial Swaps (excluding basis)	Natural Gas	0.3	2007	1.4
Short Basis Positions	Natural Gas	11.0	2007	3.3
Short Basis Positions	Natural Gas	3.3	2008	0.5
Short Basis Positions	Natural Gas	0.9	2009	0.3
Total Short Basis Positions				4.1
Total Trading Price Risk Management Liabilities				$ 10.1
NON-TRADING				
Price Risk Management Assets				
Treasury Lock	Interest Rates	N/A	2007	$ 0.9
Short Financial Swaps (excluding basis)	Natural Gas	0.1	2007	0.1
Total Non-Trading Price Risk Management Assets				$ 1.0
NON-TRADING				
Price Risk Management Liabilities				
Short Basis Positions	Natural Gas	0.2	2007	$ 0.2
Total Non-Trading Price Risk Management Liabilities				$ 0.2

The valuation of the Company s price risk management assets and liabilities were determined primarily 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 and the potential impact of liquidating the position in an orderly manner over a reasonable period of time.

Commodity Price Risk

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

Trading Activities

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

A sensitivity analysis has been prepared to estimate the Company s exposure to market risk created by trading activities. The value of trading positions is a summation of the fair values calculated for each commodity by valuing each net position at quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in quoted market prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows for 2006.

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

Non-Trading Activities

The prices of natural gas, natural gas liquids and natural gas liquids processing spreads are subject to fluctuations resulting from changes in supply and demand. The changes in these prices have a direct effect on the compensation received by the Company for operating some of its assets. To partially reduce non-trading commodity price risk, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the operating income of the Company. Because the commodities covered by these hedges are substantially the same commodities that the Company buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

A sensitivity analysis has been prepared to estimate the Company s exposure to the market risk of the Company s non-trading activities. The Company s daily net commodity position consists of natural gas inventories, commodity purchase and sales contracts, financial and commodity derivative instruments and anticipated natural gas processing spreads and fuel recoveries. Quoted market prices are not available for all of the Company s non-trading positions, therefore, the value of non-trading positions is a summation of the forecasted values calculated for each commodity based upon internally generated forecast prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in such prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows for 2006.

(In millions)	Non-Trading
Commodity market risk, net	$ 10.8

The Company may designate certain derivative instruments for the purchase or sale of physical commodities, purchase or sale of electric power and fuel procurement as normal purchases and normal sales contracts under the provisions of SFAS No. 133. Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. The Company applies normal purchases and normal sales to (i) commodity contracts for the purchase and sale of natural gas by its subsidiaries, Enogex Inc. and Enogex Gas Gathering, L.L.C.; (ii) commodity contracts for the sale of natural gas liquids produced by its subsidiary, Enogex Products Corporation; (iii) electric power contracts by OG&E; and (iv) fuel procurement by OG&E.

Credit Risk

Credit risk includes the risk that counterparties that owe 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.

For OG&E, new business customers are required to provide a security deposit in the form of cash, a bond or irrevocable letter of credit that is refunded when the account is closed. New residential customers, whose outside credit scores indicate risk, are required to provide a security deposit that is refunded after 12 months of good payment history based on the applicable utility regulation. 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.

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 condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements that provide for the netting of cash flows associated with a single counterparty. Enogex also monitors the financial condition of existing counterparties on an ongoing basis.

Item 8. Financial Statements and Supplementary Data.

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(In millions, except per share data)*	**2006**	2005	2004
OPERATING REVENUES			
Electric Utility operating revenues	**$ 1,745.7**	$ 1,720.7	$ 1,578.1
Natural Gas Pipeline operating revenues	**2,259.9**	4,190.8	3,284.5
Total operating revenues	**4,005.6**	5,911.5	4,862.6
COST OF GOODS SOLD (exclusive of depreciation shown below)			
Electric Utility cost of goods sold	**902.5**	946.6	869.1
Natural Gas Pipeline cost of goods sold	**2,000.0**	3,995.7	3,068.6
Total cost of goods sold	**2,902.5**	4,942.3	3,937.7
Gross margin on revenues	**1,103.1**	969.2	924.9
Other operation and maintenance	**416.6**	394.9	384.2
Depreciation	**181.4**	182.6	172.1
Impairment of assets	**0.3**	---	7.8
Taxes other than income	**72.1**	69.3	66.3
OPERATING INCOME	**432.7**	322.4	294.5
OTHER INCOME (EXPENSE)			
Interest income	**6.2**	3.5	4.9
Allowance for equity funds used during construction	**4.1**	---	0.9
Other income (loss)	**16.3**	(0.3)	10.5
Other expense	**(16.7)**	(5.5)	(4.7)
Net other income (expense)	**9.9**	(2.3)	11.6
INTEREST EXPENSE			
Interest on long-term debt	**87.4**	80.0	69.4
Interest expense unconsolidated affiliate	**---**	---	13.7
Allowance for borrowed funds used during construction	**(4.5)**	(2.2)	(1.7)
Interest on short-term debt and other interest charges	**13.1**	12.5	9.4
Interest expense	**96.0**	90.3	90.8
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**346.6**	229.8	215.3
INCOME TAX EXPENSE	**120.5**	68.6	73.4
INCOME FROM CONTINUING OPERATIONS	**226.1**	161.2	141.9
DISCONTINUED OPERATIONS (NOTE 8)			
Income from discontinued operations	**59.1**	84.2	18.6
Income tax expense	**23.1**	34.4	7.0
Income from discontinued operations	**36.0**	49.8	11.6
NET INCOME	**$ 262.1**	$ 211.0	$ 153.5
BASIC AVERAGE COMMON SHARES OUTSTANDING	**91.0**	90.3	88.0
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**92.1**	90.8	88.5
BASIC EARNINGS PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 2.48**	$ 1.79	$ 1.61
Income from discontinued operations, net of tax	**0.40**	0.55	0.13
NET INCOME	**$ 2.88**	$ 2.34	$ 1.74
DILUTED EARNINGS PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 2.45**	$ 1.77	$ 1.60
Income from discontinued operations, net of tax	**0.39**	0.55	0.13
NET INCOME	**$ 2.84**	$ 2.32	$ 1.73
DIVIDENDS DECLARED PER SHARE	**$ 1.3375**	$ 1.33	$ 1.33

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

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OGE ENERGY CORP.

CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2006**	2005
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 47.9**	$ 26.4
Funds on deposit	**32.0**	---
Accounts receivable, net	**344.3**	591.4
Accrued unbilled revenues	**39.7**	41.8
Fuel inventories	**65.6**	63.6
Materials and supplies, at average cost	**58.7**	56.5
Price risk management	**41.9**	116.5
Gas imbalances	**2.8**	32.0
Accumulated deferred tax assets	**10.6**	14.3
Fuel clause under recoveries	**---**	101.1
Prepayments	**9.0**	10.6
Other	**11.6**	19.4
Total current assets	**664.1**	1,073.6
OTHER PROPERTY AND INVESTMENTS, at cost	**35.2**	29.2
PROPERTY, PLANT AND EQUIPMENT		
In service	**6,307.7**	5,999.4
Construction work in progress	**191.1**	101.8
Total property, plant and equipment	**6,498.8**	6,101.2
Less accumulated depreciation	**2,631.3**	2,568.7
Net property, plant and equipment	**3,867.5**	3,532.5
In service of discontinued operations	**---**	60.6
Less accumulated depreciation	**---**	25.7
Net property, plant and equipment of discontinued operations	**---**	34.9
Net property, plant and equipment	**3,867.5**	3,567.4
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**31.1**	32.8
Regulatory asset - SFAS 158	**231.1**	---
Intangible asset - unamortized prior service cost	**---**	32.8
Prepaid benefit obligation	**---**	90.2
Price risk management	**1.7**	9.0
McClain Plant deferred expenses	**18.7**	24.9
Unamortized loss on reacquired debt	**20.1**	21.3
Unamortized debt issuance costs	**9.4**	8.1
Other	**23.1**	7.2
Deferred charges and other assets of discontinued operations	**---**	2.4
Total deferred charges and other assets	**335.2**	228.7
TOTAL ASSETS	**$ 4,902.0**	$ 4,898.9

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

OGE ENERGY CORP.

CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2006**	2005
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ ---**	$ 30.0
Accounts payable	**295.0**	510.4
Dividends payable	**31.1**	30.1
Customers deposits	**53.4**	47.8
Accrued taxes	**57.0**	67.1
Accrued interest	**37.7**	31.9
Accrued compensation	**46.0**	40.3
Long-term debt due within one year	**3.0**	---
Price risk management	**9.2**	109.5
Gas imbalances	**11.1**	36.0
Fuel clause over recoveries	**96.3**	---
Other	**33.2**	47.5
Total current liabilities	**673.0**	950.6
LONG-TERM DEBT	**1,346.3**	1,350.8
COMMITMENTS AND CONTINGENCIES (NOTE 17)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**231.3**	234.5
Accumulated deferred income taxes	**859.2**	807.1
Accumulated deferred investment tax credits	**26.8**	31.7
Accrued removal obligations, net	**125.5**	114.3
Price risk management	**1.1**	10.7
Other	**35.0**	23.4
Total deferred credits and other liabilities	**1,278.9**	1,221.7
STOCKHOLDERS EQUITY		
Common stockholders equity	**741.0**	715.5
Retained earnings	**890.8**	750.5
Accumulated other comprehensive loss, net of tax	**(28.0)**	(90.2)
Total stockholders equity	**1,603.8**	1,375.8
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$ 4,902.0**	$ 4,898.9

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

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*		**2006**	2005
STOCKHOLDERS EQUITY			
Common stock, par value $0.01 per share; authorized 125.0 shares;			
and outstanding 91.2 and 90.6 shares, respectively		**$ 0.9**	$ 0.9
Premium on capital stock		**740.1**	714.6
Retained earnings		**890.8**	750.5
Accumulated other comprehensive loss, net of tax		**(28.0)**	(90.2)
Total stockholders equity		**1,603.8**	1,375.8
LONG-TERM DEBT			
SERIES	DATE DUE		
Senior Notes - OGE Energy Corp.			
5.00 %	Senior Notes, Series Due November 15, 2014	**100.0**	100.0
Unamortized discount		**(0.7)**	(0.8)
Senior Notes - OG&E			
5.15 %	Senior Notes, Series Due January 15, 2016	**110.0**	---
6.50 %	Senior Notes, Series Due July 15, 2017	**125.0**	125.0
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**	---
Other Bonds - OG&E			
3.11% - 4.05%	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
3.20% - 4.13%	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
3.03% - 4.06%	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0
Other long-term debt (NOTE 14)		**---**	220.0
Unamortized discount		**(2.1)**	(1.4)
Enogex Notes			
8.28%	Medium-Term Notes, Series Due 2007	**3.0**	3.0
7.07%	Medium-Term Notes, Series Due 2008	**1.0**	1.0
8.125%	Medium-Term Notes, Series Due 2010	**400.0**	400.0
Unamortized swap monetization		**2.7**	3.6
Total long-term debt		**1,349.3**	1,350.8
Less long-term debt due within one year		**3.0**	---
Total long-term debt (excluding long-term debt due within one year)		**1,346.3**	1,350.8
Total Capitalization		**$ 2,950.1**	$ 2,726.6

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

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 *(In millions)*	**2006**	2005	2004
BALANCE AT BEGINNING OF PERIOD	**$ 750.5**	$ 659.8	$ 623.9
ADD: Net income	**262.1**	211.0	153.5
Total	**1,012.6**	870.8	777.4
DEDUCT: Dividends declared on common stock	**121.8**	120.3	117.6
BALANCE AT END OF PERIOD	**$ 890.8**	$ 750.5	$ 659.8

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(In millions)*	**2006**	2005	2004
Net income	**$ 262.1**	$ 211.0	$ 153.5
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment [$148.6, ($30.0) and ($21.2) pre-tax, respectively]	**91.1**	(18.4)	(13.0)
Deferred hedging gains (losses) [$4.1, $4.7 and ($1.1) pre-tax, respectively]	**2.5**	2.9	(0.7)
Reversal of unrealized gains on available-for-sale securities [($0.6) pre-tax]	**---**	---	(0.4)
Settlement and amortization of cash flow hedge [$0.5, $0.5, and ($4.0) pre-tax, respectively]	**0.3**	0.3	(2.5)
Total other comprehensive income (loss), net of tax	**93.9**	(15.2)	(16.6)
Total comprehensive income	**$ 356.0**	$ 195.8	$ 136.9

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)*	**2006**	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES			
Income from continuing operations	**$ 226.1**	$ 161.2	$ 141.9
Adjustments to reconcile income from continuing operations to net cash provided from operating activities			
Depreciation	**181.4**	182.6	172.1
Impairment of assets	**0.3**	---	7.8
Deferred income taxes and investment tax credits, net	**32.3**	21.9	50.5
Allowance for equity funds used during construction	**(4.1)**	---	(0.9)
(Gain) loss on sale of assets	**(1.6)**	0.1	(6.5)
Loss on retirement of fixed assets	**6.0**	---	---
Stock-based compensation expense	**3.8**	0.9	3.5
Excess tax benefit on stock-based compensation	**(1.4)**	---	---
Price risk management assets	**81.9**	(62.6)	(20.0)
Price risk management liabilities	**(101.7)**	80.1	9.5
Other assets	**(73.4)**	(6.4)	(28.2)
Other liabilities	**12.3**	(2.9)	7.5
Change in certain current assets and liabilities			
Funds on deposit	**(32.0)**	---	---
Accounts receivable, net	**247.1**	(106.9)	(136.5)
Accrued unbilled revenues	**2.1**	3.7	(7.5)
Fuel, materials and supplies inventories	**(4.4)**	22.1	52.5
Gas imbalance asset	**29.2**	67.8	(29.8)
Fuel clause under recoveries	**101.1**	(46.8)	(50.3)
Other current assets	**9.3**	12.4	10.0
Accounts payable	**(215.4)**	40.1	194.2
Customers deposits	**5.6**	(0.5)	6.7
Accrued taxes	**(7.2)**	53.9	(4.5)
Accrued interest	**5.8**	(0.9)	(0.7)
Accrued compensation	**5.7**	2.9	0.7
Gas imbalance liability	**(24.9)**	19.7	(6.5)
Fuel clause over recoveries	**96.3**	---	(32.4)
Other current liabilities	**(10.7)**	(4.5)	11.1
Net Cash Provided from Operating Activities	**569.5**	437.9	344.2
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(486.6)**	(297.2)	(428.6)
Proceeds from sale of assets	**3.2**	5.8	9.2
Other investing activities	**(0.1)**	0.1	0.7
Net Cash Used in Investing Activities	**(483.5)**	(291.3)	(418.7)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	**217.5**	---	186.0
Retirement of long-term debt	**---**	(254.3)	(206.2)
(Decrease) increase in short-term debt, net	**(250.0)**	125.0	(77.5)
Issuance of common stock	**14.5**	14.7	62.5
Excess tax benefit on stock-based compensation	**1.4**	---	---
Dividends paid on common stock	**(120.8)**	(120.0)	(114.6)
Net Cash Used in Financing Activities	**(137.4)**	(234.6)	(149.8)
DISCONTINUED OPERATIONS			
Net cash (used in) provided from operating activities	**(19.9)**	(43.0)	47.4
Net cash provided from (used in) investing activities	**92.8**	146.4	(3.1)
Net cash used in financing activities	**---**	(0.1)	(21.4)
Net Cash Provided from Discontinued Operations	**72.9**	103.3	22.9

NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**21.5**	15.3	(201.4)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**26.4**	11.1	212.5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 47.9**	$ 26.4	$ 11.1

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

OGE ENERGY CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

OGE Energy Corp. (collectively, with its subsidiaries, the Company) is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through two business segments, the Electric Utility and the Natural Gas Pipeline segments. All significant intercompany transactions have been eliminated in consolidation.

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

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries (Enogex) and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. The vast majority of Enogex s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. In May 2006, Enogex Gas Gathering, L.L.C. (Gathering), a wholly-owned subsidiary of Enogex Inc., sold certain gas gathering assets in the Kinta, Oklahoma, area, which have been reported as discontinued operations in the Company s Consolidated Financial Statements (see Note 8 for a further discussion). In December 2006, Enogex entered into a joint venture arrangement with a third party. The joint venture, Atoka Midstream, LLC, intends to construct, own and operate a gathering system and processing plant and related facilities relating to production in certain areas in southeastern Oklahoma. Enogex holds its 50 percent membership interest in Atoka Midstream LLC through Enogex Atoka LLC (Enogex Atoka), a wholly-owned subsidiary of Enogex Inc. Enogex Atoka will act as the managing member and operator of the facilities owned by the joint venture.

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

Accounting Records

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

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

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

December 31 *(In millions)*	**2006**	2005
Regulatory Assets		
Regulatory asset - SFAS 158	**$ 231.1**	$ ---
Income taxes recoverable from customers, net	**31.1**	32.8
Unamortized loss on reacquired debt	**20.1**	21.3
McClain Plant deferred expenses	**18.7**	24.9
Pension plan expenses	**14.7**	---
Cogeneration credit rider under recovery	**3.1**	3.7
Fuel clause under recoveries	**---**	101.1
Recoverable take or pay gas charges	**---**	4.9
Miscellaneous	**0.4**	0.5
Total Regulatory Assets	**$ 319.2**	$ 189.2
Regulatory Liabilities		
Accrued removal obligations, net	**$ 125.5**	$ 114.3
Fuel clause over recoveries	**96.3**	---
Deferred gain on sale of assets	**2.7**	3.8
Total Regulatory Liabilities	**$ 224.5**	$ 118.1

The Company adopted SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R, effective December 31, 2006, which requires the Company to separately disclose the items that have not yet been recognized as components of net periodic pension cost including, net loss, prior service cost and net transition obligation at December 31, 2006. For companies not subject to SFAS No. 71, SFAS No. 158 required this information to be included in Accumulated Other Comprehensive Income. However, for companies subject to SFAS No. 71, this information is allowed to be recorded as a regulatory asset if: (i) the utility has historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates; and (ii) there is no negative evidence that the existing regulatory treatment will change. Therefore, OG&E has recorded the net loss, prior service cost and net transition obligation as a regulatory asset as these expenses are probable of future recovery. If, in the future, the regulatory bodies indicated a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the SFAS No. 158 regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

The components of the SFAS No. 158 regulatory asset at December 31, 2006 are as follows:

December 31 *(In millions)*	**2006**
Defined benefit pension plan:	
Net loss	**$ 129.9**
Prior service cost	**21.9**
Defined benefit postretirement plans:	
Net loss	**60.3**
Net transition obligation	**15.2**
Prior service cost	**3.8**
Total	**$ 231.1**

The following amounts in the SFAS No. 158 regulatory asset at December 31, 2006 are expected to be recognized as components of net periodic benefit cost in 2007:

Defined benefit pension plan:	
Net loss	**$ 8.1**
Prior service cost	**4.7**

Defined benefit postretirement plans:		
Net loss	**5.4**	
Net transition obligation	**2.5**	
Prior service cost	**1.5**	
Total	**$**	**22.2**

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

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.

As a result of the acquisition of a 77 percent interest in the 520 megawatt (MW) natural gas-fired combined cycle NRG McClain Station (the McClain Plant) completed on July 9, 2004, and consistent with the 2002 agreed-upon settlement of an OG&E rate case (the 2002 Settlement Agreement) with the OCC, OG&E had the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition and operation of the McClain Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. At December 31, 2005, the McClain Plant regulatory asset was approximately $24.9 million which is being recovered over a four-year time period as authorized in the OCC rate order which began in January 2006. The OCC authorized approximately $15.5 million of the $24.9 million regulatory asset balance at December 31, 2005 to be included in OG&E s rate base for purposes of earning a return.

In accordance with the OCC order received by OG&E in December 2005 in its Oklahoma rate case, OG&E was allowed to recover a certain amount of pension plan expenses. At December 31, 2006, there was approximately $14.7 million of expenses exceeding this level primarily related to a pension settlement charge recorded by the Company during the fourth quarter of 2006 (see Note 15 for a further discussion). These excess amounts have been recorded as a regulatory asset as OG&E believes these expenses are probable of future recovery.

In January 2005, a cogeneration credit rider was implemented at OG&E as part of the Oklahoma retail customer electric rates in order to return purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration previously included in base rates to OG&E s customers. The balance of the cogeneration credit rider under recovery was approximately $3.1 million and $3.7 million, respectively, at December 31, 2006 and 2005. OG&E s cogeneration credit rider has been updated and approved by the OCC in December of each year through December 2006 and any over/under recovery of the cogeneration credit rider in the current year and prior periods has been automatically included in the next year s rider. OG&E s current cogeneration credit rider expired December 31, 2006. The 2007 cogeneration credit rider is approximately $80.7 million and the total under recovery through 2006 was approximately $3.1 million. OG&E expects to file an application with the OCC in late 2007 to request a cogeneration credit for years after 2007. The cogeneration credit rider under recovery was not included in OG&E s rate base and did not otherwise earn a rate of return. The cogeneration credit rider under recovery is included in Other Current Assets on the Company s Consolidated Balance Sheets.

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 typically under recovers fuel cost in periods of rising prices above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses allow OG&E to amortize under or over recovery. In accordance with the OCC order received by OG&E in December 2005 in its rate case, beginning in January 2006, OG&E s mechanism for the recovery of over or under recovered fuel costs from its customers was modified to allow interest to be applied to the over or under recovery. As described in more detail in Note 18, the OCC, in its order dated December 12, 2005, granted OG&E a $42.3 million annual increase in the rates charged by OG&E to its retail customers in Oklahoma. These increased rates became effective in January 2006 pursuant to approved tariffs filed with the OCC. In January 2007, OG&E determined that the approved tariffs had inadvertently authorized OG&E to collect, and OG&E had collected, approximately $26.7 million of additional fuel-related revenues during 2006 that was not intended by the December 12, 2005 order. As a result, OG&E filed with the OCC in January 2007 amendments to its previously-authorized tariffs, in order to cease recovery of the fuel-related revenues not intended by the December 12, 2005 order. The $26.7 million, plus $1.2 million of interest, was recorded as a liability under Fuel Clause Over Recoveries on the Consolidated Balance Sheet in the fourth quarter of 2006, and such amounts, along with other Fuel Clause Over Recoveries, will be credited to OG&E s Oklahoma customers in 2007 and 2008 through OG&E s automatic fuel adjustment clause. In addition, OG&E recorded a reduction in operating revenues of approximately $26.7 million and an increase in interest expense of approximately $0.5 million, which resulted in an after tax reduction in net income of approximately $16.7 million in the fourth quarter of 2006. Because the rate increase authorized in the December 2005 order was not implemented until January 2006 and the tariffs were corrected effective December 31, 2006, the $26.7 million had no impact on net income for the year ended December 31, 2006. See additional discussion in Supplementary Data Interim Consolidated Financial Information (Unaudited).

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations. In accordance with SFAS No. 143, Accounting for Asset Retirement Obligations, OG&E was required to reclassify its accrued removal obligations, which had previously been recorded as a liability in Accumulated Depreciation, to a regulatory liability.

During 2004, OG&E sold assets including its interest in certain natural gas producing properties and the sale of land near the Company s principal executive offices for a gain of approximately $3.5 million. During 2005, OG&E sold certain assets for a gain of approximately $0.3 million. In December 2005, the OCC order in OG&E s Oklahoma rate case required that any previously recognized gain in 2004 related to the sale of assets should be returned to customers through electric rates at a rate of approximately $1.3 million annually. During 2005, OG&E reversed these gains and reclassified them to Other Deferred Credits and Other Liabilities as a regulatory liability. OG&E recorded gains from the sale of assets in 2005 and 2006 in a similar manner and expects to continue that treatment for future gains from the sale of assets.

Management continuously monitors the future recoverability of regulatory assets. When in management s judgment future recovery becomes impaired, the amount of the regulatory asset is reduced or written off, as appropriate. If the Company were required to discontinue the application of SFAS No. 71 for some or all of its operations, it could result in writing off the related regulatory assets; the financial effects of which could be significant.

Use of Estimates

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

Cash and Cash Equivalents

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

The Company s cash management program utilizes controlled disbursement banking arrangements. Outstanding checks in excess of cash balances were approximately $45.0 million and $55.0 million at December 31, 2006 and 2005, respectively, and are classified as Accounts Payable in the Consolidated Balance Sheets. Sufficient funds were available to fund these outstanding checks when they were presented for payment.

Allowance for Uncollectible Accounts Receivable

For OG&E, customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. The allowance for uncollectible accounts receivable for Enogex is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when the Company believes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was approximately $4.4 million and $3.7 million at December 31, 2006 and 2005, 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 after 12 months of good payment history based on the applicable utility regulation. 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 condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty. Enogex also monitors the financial condition 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. These inventories are accounted for under the last-in, first-out (LIFO) cost method. The estimated replacement cost of fuel inventories was higher than the stated LIFO cost by approximately $13.7 million and $19.1 million for 2006 and 2005, respectively, based on the average cost of fuel purchased. The amount of fuel inventory was approximately $29.7 million and $27.9 million at December 31, 2006 and 2005, respectively.

Enogex

Natural gas inventory is held by Enogex Inc. and OGE Energy Resources, Inc. (OERI). Enogex Inc. maintains of natural gas inventory to provide operational support for its pipeline deliveries. As part of its recurring business activity, OERI injects and withdraws natural gas in to and out of inventory under the terms of its storage capacity contracts. In order to mitigate market price exposures, OERI enters into contracts or hedging instruments to protect the cash flows associated with its inventory. OERI has elected not to designate inventory hedging contracts as fair value or cash flow hedges under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. The fair value of the hedging instruments is recorded on the books of OERI as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2006, Enogex recorded write-downs to market value related to natural gas storage inventory of approximately $18.7 million. The amount of Enogex s natural gas inventory was approximately $35.9 million and $35.7 million at December 31, 2006 and 2005, respectively. Natural gas storage inventory is presented in Fuel Inventories on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by Enogex s pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or made up in-kind. Enogex values all imbalances at an average of current market indices applicable to Enogex s operations, not to exceed net realizable value. Also included in Gas Imbalances on the Consolidated Balance Sheets are planned or managed imbalances related to OERI s business, referred to as park and loan transactions. Park and loan assets were approximately $15.7 million at December 31, 2005 and park and loan liabilities were approximately $10.2 million at December 31, 2005. There were no park and loan assets or liabilities at December 31, 2006. Operational imbalance assets were approximately $2.8 million and $16.3 million, respectively, at December 31, 2006 and 2005 and operational imbalance liabilities were approximately $11.1 million and $25.8 million, respectively, at December 31, 2006 and 2005.

Property, Plant and Equipment

OG&E

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

OG&E owns a 77 percent in the McClain Plant and, as disclosed below, only OG&E s 77 percent interest is reflected in the balances in the table below. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority (OMPA). OG&E and the OMPA are responsible for providing their own financing of capital expenditures. Also, only OG&E s proportionate interest of any direct expenses of the McClain Plant such as fuel, maintenance expense and other operating expenses is included in the applicable financial statements captions in the Consolidated Statements of Income. The balance of OG&E s interest in the McClain Plant asset is approximately $176.2 million and $174.0 million, respectively, at December 31, 2006 and 2005. The accumulated depreciation associated with OG&E s interest in the McClain Plant is approximately $24.9 million and $14.3 million, respectively, at December 31, 2006 and 2005.

Enogex

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

The Company s property, plant and equipment are divided into the following major classes at December 31, 2006 and 2005, respectively.

December 31 *(In millions)*	**2006**	2005
OGE Energy Corp. (holding company)		
Property, plant and equipment	**$ 80.7**	$ 76.3
OGE Energy Corp. property, plant and equipment	**80.7**	76.3
OG&E		
Distribution assets	**2,205.3**	2,080.6
Electric generation assets	**2,057.4**	1,907.1
Transmission assets	**663.2**	610.2
Intangible plant	**32.0**	8.6
Other property and equipment	**196.5**	221.4
OG&E property, plant and equipment	**5,154.4**	4,827.9
Enogex		

Transportation and storage assets	**691.5**	683.6
Gathering and processing assets	**564.6**	505.9
Marketing assets	**7.6**	7.5
Enogex property, plant and equipment	**1,263.7**	1,197.0
Total property, plant and equipment	**$ 6,498.8**	$ 6,101.2

Depreciation

OG&E

The provision for depreciation, which was approximately 2.7 percent and 3.0 percent, respectively, of the average depreciable utility plant for 2006 and 2005, is provided on a straight-line method over the estimated service life of the utility assets. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant, and is based on the average life group method. In 2007, the provision for depreciation is projected to be approximately 2.7 percent of the average depreciable utility plant. Amortization of intangibles other than debt costs is computed using the straight-line method. Approximately 81 percent of the amortizable intangible plant balance at December 31, 2006 will be amortized over three years with the remaining intangible plant being amortized over their respective lives ranging up to 25 years.

Enogex

Depreciation is computed principally on the straight-line method using estimated useful lives of three to 83 years for transportation and storage assets, three to 30 years for gathering and processing assets and three to 10 years for marketing assets. Amortization of intangibles other than debt costs is computed using the straight-line method over the respective lives of the intangibles ranging up to 20 years.

Impairment of Assets

The Company assesses potential impairments of assets or asset groups when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset or asset group. For purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Estimates of future cash flows used to test the recoverability of a long-lived asset or asset group shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset or asset group. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flow. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets is not known at this time.

Allowance for Funds Used During Construction

For OG&E, AFUDC is calculated according to the FERC pronouncements for the imputed cost of equity and borrowed funds. AFUDC, a non-cash item, is reflected as a credit in the Consolidated Statements of Income and as a charge to Construction Work in Progress in the Consolidated Balance Sheets. AFUDC rates, compounded semi-annually, were 7.79 percent, 3.78 percent and 4.99 percent for the years 2006, 2005 and 2004, respectively. The increase in the AFUDC rates in 2006 was primarily due to increased equity funds in the AFUDC calculation that resulted from a higher level of construction costs partially offset by a lower level of short-term borrowings in 2006.

Revenue Recognition

OG&E

OG&E reads its customers meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers electricity consumption that has not been billed at the end of each month. An amount is accrued as a receivable for this unbilled revenue based on estimates of usage and prices during the period. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Enogex

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

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

The Company recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with natural gas liquids is recognized when the production is sold. Substantially all of OERI s natural gas contracts qualify as derivatives and, therefore, are accounted for at fair value as prescribed in SFAS No. 133. Under fair value accounting, fixed-price forwards, swaps, options, futures and other financial instruments with third parties are recorded at estimated fair market values, net of reserves, with the corresponding market changes in fair value recognized in earnings and offsetting amounts recorded as Price Risk Management assets, liabilities or against the brokerage deposits in Other Current Assets in the Consolidated Balance Sheets.

Automatic Fuel Adjustment Clauses

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

Stock-Based Compensation

The Company adopted SFAS No. 123 (Revised), Share-Based Payment, using the modified prospective transition method, effective January 1, 2006, which required the Company to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. See Note 3 for a further discussion related to the Company s stock-based compensation. The following table reflects pro forma net income and income per average common share for 2005 and 2004 had the Company elected to adopt the fair value recognition provisions of SFAS No. 123, Accounting for Stock-Based Compensation, for options granted under the Company s stock-based employee compensation plans. For purposes of this pro forma disclosure, the value of the options was determined using a Black-Scholes option pricing formula and amortized to expense over the options vesting periods. Pro forma information is not included for 2006 as all share-based payments have been accounted for under SFAS No. 123(R).

Year ended December 31 *(In millions, except per share data)*	2005	2004
Net income, as reported	$ 211.0	$ 153.5
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	---	---
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	0.5	1.0

Pro forma net income	$ 210.5	$ 152.5
Income per average common share		
Basic as reported	$ 2.34	$ 1.74
Diluted as reported	$ 2.32	$ 1.73
Basic pro forma	$ 2.33	$ 1.73
Diluted pro forma	$ 2.32	$ 1.72

Accrued Vacation

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

Accumulated Other Comprehensive Loss

The components of accumulated other comprehensive loss at December 31, 2006 and 2005 are as follows:

December 31 *(In millions)*	**2006**	2005
Defined benefit pension plan:		
Net loss, net of tax	**$ (21.4)**	$ ---
Prior service cost, net of tax	**(3.4)**	---
Defined benefit postretirement plans:		
Net loss, net of tax	**(5.4)**	---
Net transition obligation, net of tax	**(0.8)**	---
Prior service cost, net of tax	**(0.7)**	---
Deferred hedging gains, net of tax	**5.6**	3.1
Settlement and amortization of cash flow hedge, net of tax	**(1.9)**	(2.2)
Minimum pension liability adjustment, net of tax	**---**	(91.1)
Total accumulated other comprehensive loss, net of tax	**$ (28.0)**	$ (90.2)

Defined Benefit Pension and Postretirement Plans

The Company adopted certain provisions of SFAS No. 158 effective December 31, 2006, which requires the Company to separately disclose the items that have not yet been recognized as components of net periodic pension cost including, net loss, prior service cost and net transition obligation at December 31, 2006. The below amounts exclude amounts related to OG&E, since under SFAS No. 71, OG&E is allowed to record these expenses as a regulatory asset (see Note 1 for a future discussion). Accumulated other comprehensive loss included an after tax loss of approximately $21.4 million ($34.9 million pre-tax) and $3.4 million ($5.6 million pre-tax) at December 31, 2006 related to the net loss and prior service cost of its defined benefit pension plan, respectively. Accumulated other comprehensive loss included an after tax loss of approximately $5.4 million ($11.7 million pre-tax), $0.8 million ($1.2 million pre-tax) and $0.7 million ($1.2 million pre-tax) at December 31, 2006 related to the net loss, net transition obligation and prior service cost of its defined benefit postretirement plans, respectively.

The following amounts in accumulated other comprehensive loss at December 31, 2006 are expected to be recognized as components of net periodic benefit cost in 2007:

Defined benefit pension plan:	
Net loss, net of tax	**$ 1.3**
Prior service cost, net of tax	**0.7**
Defined benefit postretirement plans:	
Net loss, net of tax	**0.6**
Prior service cost, net of tax	**0.3**
Net transition obligation, net of tax	**0.1**
Total	**$ 3.0**

Minimum Pension Liability Adjustment

Accumulated other comprehensive loss included an after tax loss of approximately $91.1 million ($148.6 million pre-tax) at December 31, 2005 related to a minimum pension liability adjustment based on a review of the funded status of the Company s pension plan by the Company s actuarial consultants as of December 31, 2005.

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 and Enogex have been designated as one of several potentially responsible parties, the amount accrued represents OG&E s and Enogex s estimated share of the cost.

Reclassifications

Certain prior year amounts have been reclassified on the Consolidated Financial Statements to conform to the 2006 presentation primarily related to discontinued operations.

2. Accounting Pronouncements

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109, which clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. The Company adopted this new interpretation effective January 1, 2007. As prescribed in the interpretation, the cumulative effect of applying the provisions of FIN No. 48 shall be reflected as an adjustment to the opening balance of Stockholders Equity. The Company estimates that this cumulative effect will be between approximately $3 million and $5 million. The Company also anticipates additional interest expense will be incurred during 2007 related to the method of accounting used to capitalize costs for self-constructed assets (see Note 10 for a further discussion).

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 expands disclosures about the use of fair value to measure assets and liabilities in interim and annual periods subsequent to initial recognition. The guidance in SFAS No. 157 applies to derivatives and other financial instruments measured at fair value under SFAS No. 133 at initial recognition and in all subsequent periods. Therefore, SFAS No. 157 nullifies the guidance in footnote 3 of Emerging Issues Task Force Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities. SFAS No. 157 also amends SFAS No. 133 to remove the guidance similar to that nullified in EITF 02-3. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The provisions of SFAS No. 157 should be applied prospectively as of the beginning of the fiscal year in which it is initially applied, except in certain conditions. The Company will adopt this new standard effective January 1, 2008. Management has not yet determined what the impact of this new standard will be on its consolidated financial position or results of operations.

In September 2006, the FASB issued SFAS No. 158 which requires an employer to: (i) recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity; and (ii) to measure the fair value of the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. The requirement to initially recognize the funded status of the defined benefit postretirement plan and the disclosure requirements are effective for the year ended December 31, 2006 for the Company. The requirement to measure plan assets and benefit obligations at fair value in accordance with SFAS No. 157 as of the date of the employer s fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. The Company adopted provision (i) above of this new standard effective December 31, 2006. At December 31, 2006, the projected benefit obligation and fair value of assets of the Company s pension plan and restoration of retirement income plan was approximately $585.0 million and $519.4 million, respectively, for an underfunded status of approximately $65.6 million. Also, at December 31, 2006, the accumulated postretirement benefit obligation and fair value of assets of the Company s postretirement benefit plans was approximately $225.4 million and $74.0 million, respectively, for an underfunded status of approximately $151.4 million. The above amounts have been recorded in Accrued Pension and 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 Company will adopt provision (ii) above of this new standard effective December 31, 2008. Management has not yet determined what the impact of provision (ii) of this new standard will be on its consolidated financial position or results of operations.

3. Stock-Based Compensation

On January 21, 1998, the Company adopted a Stock Incentive Plan (the 1998 Plan). In 2003, the Company adopted, and its shareowners approved, a new Stock Incentive Plan (the 2003 Plan and together with the 1998 Plan, the Plans). The 2003 Plan replaced the 1998 Plan and no further awards will be granted under the 1998 Plan. As under the 1998 Plan, under the 2003 Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees. The Company has authorized the issuance of up to 2,700,000 shares under the 2003 Plan.

Prior to January 1, 2006, the Company accounted for the Plans under the recognition and measurement provisions of Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, as permitted by SFAS No. 123. The Company also previously adopted the disclosure provisions under SFAS No. 123 and SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure. The Company recorded compensation expense of approximately $0.9 million pre-tax ($0.5 million after tax) and $3.5 million pre-tax ($2.1 million after tax) in 2005 and 2004, respectively, related to its performance units in Other Operation and Maintenance Expense in the Consolidated Statements of Income. No compensation expense related to stock options was recognized in 2005 or 2004 as all options granted under those plans had an exercise price equal to the market value of the Company s common stock on the grant date. Effective January 1, 2006, the Company adopted SFAS No. 123(R) using the modified prospective transition method. Under that transition method, compensation cost recognized in the first quarter of 2006 included: (i) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the fair value calculated in accordance with the provisions of SFAS No. 123(R); and (ii) compensation cost for all share-based payments granted in the first quarter of 2006 based on the fair value calculated in accordance with the provisions of SFAS No. 123(R). Results for prior periods were not restated.

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded a cumulative effect adjustment of approximately $0.4 million pre-tax ($0.2 million after tax, or less than $0.01 per basic and diluted share) on January 1, 2006 for outstanding non-vested share-based compensation grants at December 31, 2005, which is not included in the amounts discussed below. The Company determined that the cumulative effect adjustment was immaterial for presentation purposes and is, therefore, included in Other Operation and Maintenance Expense in the Consolidated Statement of Income. The Company recorded compensation expense of approximately $8.6 million pre-tax ($5.3 million after tax, or $0.06 per basic and diluted share) in 2006 related to the Company s share-based payments.

Prior to the adoption of SFAS No. 123(R), the Company presented all tax benefits of deductions resulting from the exercise of stock options or other share-based payments as operating cash flows in the Consolidated Statements of Cash Flows. SFAS No. 123(R) requires cash flows resulting in tax benefits from tax deductions in excess of the compensation cost recognized for share-based payments (excess tax benefits) to be classified as financing cash flows. The Company recorded an excess tax benefit of approximately $2.8 million in 2006 related to the Company s 2006 share-based payments, which amount will be presented as a financing cash inflow and realized when the Company s 2006 income tax return is completed in 2007. The Company realized an excess tax benefit of approximately $1.4 million in 2006 related to the Company s 2005 share-based payments, which amount was presented as a financing cash inflow and realized when the Company s 2005 income tax return was filed in August 2006. The Company realized an excess tax benefit of approximately $0.8 million during 2005 related to the Company s 2004 share-based payments. The Company did not realize an excess tax benefit during 2004 related to the Company s 2003 share-based payments.

Performance Units

Under the Plans, the Company has issued performance units which represent the value of one share of the Company s common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the Plans). Each performance unit is subject to forfeiture if the recipient terminates employment with the Company or a subsidiary prior to the end of the three-year award cycle for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant s number of full months of service during the three-year award cycle, further adjusted based on the achievement of the performance goals during the award cycle. The following table is a summary of the terms of the Company s outstanding performance units awarded during 2004, 2005 and 2006.

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Condition	Settlement		Vesting Period	SFAS No. 123(R) Classification
Total Shareholder Return	2/3	Stock (A)	3-year cliff	Equity
	1/3	Cash	3-year cliff	Liability
Earnings Per Share	2/3	Stock (A)	3-year cliff	Equity
	1/3	Cash	3-year cliff	Liability

(A) All of the Company s 2006 performance units will be settled in stock.

The performance units granted based on total shareholder return (TSR) are contingently awarded and will be payable in cash or shares of the Company s common stock (other than performance units awarded in 2006, which will be payable only in shares of 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 is dependent on the Company s TSR ranking relative to a peer group of companies. The performance units granted based on earnings per share (EPS) are contingently awarded and will be payable in cash or shares of the Company s common stock (other than performance units awarded in 2006, which will be payable only in shares of common stock) based on the Company s EPS growth over a three-year award cycle compared to a target set at the time of the grant by the Compensation Committee of the Company s Board of Directors. If there is no or only a partial payout for the performance units at the end of the three-year award cycle, the unearned performance units are cancelled. During 2006, 2005 and 2004, respectively, the Company awarded 239,856, 201,794 and 162,591 performance units to certain employees of the Company and its subsidiaries.

Performance Units Total Shareholder Return

The Company recorded compensation expense of approximately $6.5 million pre-tax ($4.0 million after tax) in 2006 related to the performance units based on TSR. The Company recorded compensation expense of approximately $0.6 million pre-tax ($0.4 million after tax) and $3.6 million pre-tax ($2.2 million after tax) in 2005 and 2004, respectively, related to the performance units based on TSR. The fair value of the performance units based on TSR was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units settled in stock 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. Compensation expense for the performance units settled in cash is based on the change in the fair value of the performance units for each reporting period. This liability for the performance units will be remeasured at each reporting date until the date of settlement. Dividends are not accrued or paid during the performance period and, therefore, are not included in the fair value calculation. Expected price volatility is based on the historical volatility of the Company s common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the three-year award cycle. There are no post-vesting restrictions related to the Company s performance units based on TSR. The fair value of the performance units based on TSR was calculated based on the following assumptions at the grant date.

	2006	2005	2004
Expected dividend yield	4.9%	5.3%	6.5%
Expected price volatility	16.8%	22.3%	23.0%
Risk-free interest rate	4.66%	3.28%	2.47%
Expected life of units (in years)	2.85	2.85	2.94
Fair value of units granted	$ 22.93	$ 21.56	$ 20.10

The fair value of the performance units based on TSR which are settled in cash was remeasured at December 31, 2006 based on the following assumptions.

2005

Expected dividend yield	4.0%
Expected price volatility	15.8%
Risk-free interest rate	4.96%
Expected life of units (in years)	1.00
Fair value of units at 12/31/06	$ 62.62

A summary of the activity for the Company s performance units based on TSR at December 31, 2006 and changes during 2006 are summarized in the following table. Following the end of a three-year performance period, payout of the performance units based on TSR is determined by the Company s TSR for such period compared to a peer group and payout requires the approval of the Compensation Committee of the Company s Board of Directors. Payouts, if any, are made in two-thirds stock and one-third cash (other than payouts of performance units awarded in 2006, which will be made only in common stock) and are considered made when the payout is approved by the Compensation Committee.

(dollars in millions)	Number of Units	Stock Conversion Ratio (A)	Aggregate Intrinsic Value
Units Outstanding at 12/31/05	385,536	1 : 1	
Granted (B)	179,896	1 : 1	
Converted	(111,235)	1 : 1	$ 4.3
Forfeited	(13,934)	1 : 1	
Units Outstanding at 12/31/06	440,263	1 : 1	$ 32.5
Units Fully Vested at 12/31/06 (C)	132,845	1 : 1	$ 9.3

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

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

(C) These performance units awarded in 2004 became fully vested at December 31, 2006 and if certified by the Compensation Committee of the Company s Board of Director s will be converted in February 2007.

A summary of the activity for the Company s non-vested performance units based on TSR at December 31, 2006 and changes during 2006 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/05	274,301	$ 20.84
Granted (D)	179,896	$ 22.93
Vested (E)	(132,845)	$ 20.10
Forfeited	(13,934)	$ 22.11
Units Non-Vested at 12/31/06 (F)	307,418	$ 22.33

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

(E) These performance units awarded in 2004 became fully vested at December 31, 2006 and if certified by the Compensation Committee of the Company s Board of Director s will be converted in February 2007.

(F) Of the 307,418 performance units not vested at December 31, 2006, 267,650 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2006, there was approximately $3.7 million in unrecognized compensation cost related to non-vested performance units based on TSR which is expected to be recognized over a weighted-average period of 1.61 years.

Performance Units Earnings Per Share

The Company recorded compensation expense of approximately $2.0 million pre-tax ($1.2 million after tax) in 2006 related to the performance units based on EPS. The Company recorded compensation expense of approximately $0.5 million pre-tax ($0.3 million after tax) in 2005 related to the performance units based on EPS. No compensation expense related to performance units based on EPS was recognized in 2004 as the 2004 performance units did not have an EPS component. The fair value of the performance units based on EPS is based on grant date fair value which is equivalent to the price of one share of the Company s common stock on the date of grant. The fair value of performance units based on EPS varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. The Company reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to the Company s performance units based on EPS. The grant date fair value of the 2005 and 2006 performance units was $23.78 and $28.00, respectively.

A summary of the activity for the Company s performance units based on EPS at December 31, 2006 and changes during 2006 are summarized in the following table. Following the end of a three-year performance period, payout of the

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performance units based on EPS growth is determined by the Company s growth in EPS for such period compared to a target set at the beginning of the three-year period by the Compensation Committee of the Company s Board of Directors and payout requires the approval of the Compensation Committee. Payouts, if any, are made in two-thirds stock and one-third cash (other than payouts of performance units awarded in 2006, which will be made only in common stock) and are considered made when approved by the Compensation Committee.

(dollars in millions)	Number of Units	Stock Conversion Ratio (B)	Aggregate Intrinsic Value
Units Outstanding at 12/31/05	46,531	1:1	
Granted (A)	59,960	1:1	
Forfeited	(4,032)	1:1	
Units Outstanding at 12/31/06	102,459	1:1	$ 8.2

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

(B) These performance units awarded in 2004 became fully vested at December 31, 2006 and if certified by the Compensation Committee of the Company s Board of Director s will be converted in February 2007.

A summary of the activity for the Company s non-vested performance units based on EPS at December 31, 2006 and changes during 2006 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/05	46,531	$ 23.78
Granted (C)	59,960	$ 28.00
Forfeited	(4,032)	$ 26.40
Units Non-Vested at 12/31/06 (D)	102,459	$ 26.15

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

(D) Of the 102,459 performance units not vested at December 31, 2006, 89,203 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2006, there was approximately $2.6 million in unrecognized compensation cost related to non-vested performance units based on EPS which is expected to be recognized over a weighted-average period of 1.7 years.

Stock Options

The Company recorded compensation expense of approximately $0.1 million pre-tax (less than $0.1 million after tax) in 2006 related to stock options. During 2006 and 2005, no stock options were granted under the 2003 Plan. During 2004, 380,400 stock options were granted under the 2003 Plan. Compensation expense for the non-vested stock options at December 31, 2005 was a fixed amount determined at the grant date fair value and was recognized over the remaining vesting period during 2006. No compensation expense related to stock options was recognized in 2005 or 2004 as all options granted under those plans had an exercise price equal to the market value of the Company s common stock on the grant date. The Company accounts for stock option grants as separate grants. The options granted under the Plans vest in one-third annual installments beginning one year from the date of grant and have a contractual life of 10 years. Each option is subject to forfeiture if the recipient terminates employment with the Company or a subsidiary for any reason other than death, disability or retirement. Dividends are not paid or accrued on unexercised options. The options provide for accelerated vesting if there is a change in control (as defined in the Plans). The fair value of each option grant under the Plans is estimated on the grant date using the Black-Scholes option pricing model that factors in information, including the expected dividend yield, expected price volatility and risk-free interest rate. The fair value was $2.05 at the grant date for the stock options that are not fully vested at December 31, 2006 and was calculated based on the following assumptions at the grant date.

	2004
Expected dividend yield	6.27%
Expected price volatility	18.58%
Risk-free interest rate	3.77%
Expected life of options (in years)	7
Weighted-average fair value of options granted	$ 2.05

A summary of the activity for the Company s options at December 31, 2006 and changes during 2006 are summarized in the following table:

(dollars in millions)	Number of Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
Options Outstanding at 12/31/05	2,139,376	$ 22.20		
Exercised	(634,973)	$ 22.79	$ 7.2	
Expired	(15,200)	$ 26.58		
Forfeited	(3,601)	$ 21.41		
Options Outstanding at 12/31/06	1,485,602	$ 21.90	$26.90	4.86 years
Options Fully Vested and Exercisable at 12/31/06	1,394,220	$ 21.79	$25.40	4.74 years

A summary of the activity for the Company s non-vested options at December 31, 2006 and changes during 2006 are summarized in the following table:

	Number of Options	Weighted-Average Grant Date Fair Value
Options Non-Vested at 12/31/05	404,398	$ 1.95
Vested	(294,215)	$ 2.02
Expired	(15,200)	$ ---
Forfeited	(3,601)	$ 1.99
Options Non-Vested at 12/31/06 (A)	91,382	$ 2.05

(A) All of the 91,382 stock options not vested at December 31, 2006 vested in January 2007.

At December 31, 2006, there was no unrecognized compensation cost related to non-vested options, which became fully vested in January 2007.

The Company issues new shares to satisfy stock option exercises. The Company received approximately $14.5 million in 2006 related to exercised stock options. The Company recorded an excess tax benefit of approximately $2.8 million in 2006 related to the Company s 2006 share-based payments, which amount will be presented as a financing cash inflow and realized when the Company s 2006 income tax return is completed in 2007. The Company realized an excess tax benefit of approximately $1.4 million in 2006 related to the Company s 2005 share-based payments, which amount was presented as a financing cash inflow and realized when the Company s 2005 income tax return was filed in August 2006. The Company realized an excess tax benefit of approximately $0.8 million during 2005 related to the Company s 2004 share-based payments. The Company did not realize a excess tax benefit during 2004 related to the Company s 2003 share-based payments.

4. Asset Retirement Obligations

In accordance with SFAS No. 143 for periods subsequent to the initial measurement of an asset retirement obligations (ARO), an entity shall recognize period-to-period changes in the liability for an ARO resulting from: (i) the passage of time; and (ii) revisions to either the timing or the amount of the original estimate of undiscounted cash flows. During the second quarter of 2006, the Company reviewed its initial ARO valuations and determined that there were changes in the liability of the ARO related to power plant structure legal obligations resulting from revisions to the amount of the original estimate of undiscounted cash flows. As a result, an ARO of approximately $1.0 million was recognized as an increase in the carrying amount of the liability for an ARO and an increase in the related asset retirement cost capitalized as part of the carrying amount of the related long-lived asset with no effect on net income. There were no changes made to previously recorded ARO s during the last six months of 2006. Also, in the fourth quarter of 2006, OG&E recorded an additional ARO for approximately $0.9 million related to its Centennial wind farm. Beginning January 1, 2007, OG&E will amortize the remaining value of the related ARO asset over the estimated remaining life of 99 years. The Company has also identified other ARO s that have not been recorded because the Company determined that these assets have indefinite lives primarily related to Enogex s processing plants and compression sites.

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

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

6. Asset Sales

During September 2004, Enogex received notification from a customer that a transportation agreement involving four of Enogex s non-contiguous pipeline asset segments located in West Texas and used to serve the customer s power plants would be terminated effective December 31, 2004. In response to this notification, the Company recognized, during the third quarter of 2004, a pre-tax impairment loss of approximately $8.6 million in the Natural Gas Pipeline segment related to Enogex natural gas pipeline assets that were used to provide service to this customer. In December 2004, the Company received notification that all of this customers plants in West Texas were shut down and service was no longer required. In November 2006, Enogex sold the four non-contiguous pipeline asset segments for approximately $1.0 million. Enogex recognized a pre-tax gain of approximately $1.0 million in the fourth quarter of 2006 related to the sale of these assets. These assets were part of the Natural Gas Pipeline segment.

7. Price Risk Management Assets and Liabilities

Non-Trading Activities

The Company periodically utilizes derivative contracts to manage the exposure of its assets to unfavorable changes in commodity prices, as well as to reduce exposure to adverse interest rate fluctuations. During 2006 and 2005, the Company s use of non-trading price risk management instruments involved the use of commodity price futures, commodity price swap contracts, interest rate swap agreements and treasury lock agreements. The commodity price futures, commodity price swap contracts and interest rate swap agreements involved the exchange of fixed price or rate payments in exchange for floating price or rate payments over the life of the instrument without an exchange of the underlying principal amount. The treasury lock agreements in late 2005 protected against the variability of future interest payments of long-term debt that was issued by OG&E in January 2006 and the treasury lock agreement in November 2006 is to protect against the variability of future interest payments of long-term debt that is expected to be issued during the first half of 2007.

In accordance with SFAS No. 133, the Company recognizes its non-exchange traded derivative instruments as Price Risk Management assets or liabilities in the Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Consolidated Balance Sheets. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative instrument is recognized in current earnings on the same line item as the gain or loss recorded for the change in the fair value of the hedged item. For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portio n of a derivative s change in fair value is recognized currently in earnings. Forecasted transactions designated as the hedged item in a cash flow hedge are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings. If the forecasted transactions are no longer reasonably possible of occurring, any associated amounts recorded in Accumulated Other Comprehensive Income will also be recognized directly in earnings.

The Company may designate certain derivative instruments for the purchase or sale of physical commodities, purchase or sale of electric power and fuel procurement as normal purchases and normal sales contracts under the provisions of SFAS No. 133. Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. The Company applies normal purchases and normal sales to: (i) commodity contracts for the purchase and sale of natural gas by its subsidiaries, Enogex Inc. and Enogex Gas Gathering, L.L.C.; (ii) commodity contracts for the sale of natural gas liquids produced by its subsidiary, Enogex Products Corporation (Products); (iii) electric power contracts by OG&E; and (iv) fuel procurement by OG&E.

At December 31, 2006 and 2005, the Company had no outstanding interest rate swap agreements. At December 31, 2006, OG&E s treasury lock agreement has been designated as a cash flow hedge under SFAS No. 133. At December 31, 2005, OG&E had two separate treasury lock agreements designated as cash flow hedges under SFAS No. 133, which were terminated on January 6, 2006 after OG&E issued long-term debt. The Company measures ineffectiveness of the cash flow hedges under the hypothetical derivative method prescribed by SFAS No. 133. Under the hypothetical derivative method, the Company has designated that the critical terms of the hedging instrument are the same as the critical terms of the hypothetical derivative used to value the forecasted transaction, and, as a result, no ineffectiveness is expected.

Trading Activities

The Company, through its subsidiary, OERI, engages in energy trading activities primarily related to the purchase and sale of natural gas. Contracts utilized in these activities generally include forward swap contracts as well as over-the-counter and exchange traded futures and options. Energy trading activities are accounted for in accordance with SFAS No. 133 and EITF Issue No. 02-3. In accordance with SFAS No. 133, financial instruments that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as Price Risk Management assets or liabilities in the Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement or against the brokerage deposits in Other Current Assets. Unrealized gains and losses from changes in the market value of open contracts are included in Natural Gas Pipeline Operating Revenues in the Consolidated Statements of Income. Energy trading contracts resulting in delivery of a commodity that meet the requirements of EITF Issue No. 99-19, Reporting Revenues Gross as a Principal or Net as an Agent, are included as sales or purchases in the Consolidated Statements of Income depending on whether the contract relates to the sale or purchase of the commodity.

In accordance with FASB Interpretation No. 39 (As Amended), Offsetting of Amounts Related to Certain Contracts an interpretation of APB Opinion No. 10 and FASB Statement No. 105, fair value amounts recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity s choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the consolidated balance sheet.

In the Company s Consolidated Balance Sheets at December 31, 2006 and 2005, the fair value of transactions with the same counterparty is presented on a gross basis, consistent with past practice. However, OERI has energy trading contracts with set off provisions with various counterparties. If these transactions with the same counterparty were presented on a net basis in the Consolidated Balance Sheets, Price Risk Management assets and liabilities would be approximately $40.0 million and $6.7 million at December 31, 2006, respectively, and would be approximately $98.0 million and $92.8 million at December 31, 2005, respectively.

8. Enogex Discontinued Operations

In April 2005, Enogex Compression Company, LLC (Enogex Compression) received an unsolicited offer to buy its interest in Enerven Compression Services, LLC (Enerven), a joint venture focused on the rental of natural gas compression assets. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business.

Enogex regularly evaluates the long term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on these evaluations, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in Enogex Arkansas Pipeline Corporation (EAPC), which held the 75 percent interest in the NOARK Pipeline System Limited Partnership. This sale was completed on October 31, 2005. The Company received approximately $177.4 million in cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter of 2005. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million, was used, among other things, to reduce short-term debt levels and fund capital expenditures.

In March 2006, Enogex announced that its wholly-owned subsidiary, Gathering, had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction were approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and Enogex recorded an after tax gain of approximately $34.1 million during the second quarter of 2006. The proceeds from the sale, were used, among other things, to reduce short-term debt levels and fund capital expenditures.

The Consolidated Financial Statements of the Company have been reclassified to reflect Enogex Compression s sale of its Enerven interest, Enogex s sale of its EAPC interest and Gathering s gas gathering assets in Kinta, Oklahoma, all of which were part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of Enerven, EAPC and the Gathering assets that were sold have been excluded from the respective captions in the Consolidated Financial Statements and have been separately reported as discontinued operations in the applicable financial statement captions. Enogex Compression s sale of its Enerven interest and Enogex s sale of its EAPC interest were completed during 2005 and, therefore, there are no results of operations for these transactions during 2006. Summarized financial information for the discontinued operations as of December 31 is as follows:

CONSOLIDATED STATEMENTS OF INCOME DATA

Year ended December 31 *(In millions)*	**2006**	2005	2004
Operating revenues from discontinued operations	**$ 9.4**	$ 106.0	$ 120.1
Income from discontinued operations before taxes	**59.1**	84.2	18.6

9. Supplemental Cash Flow Information

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

Year ended December 31 *(In millions)*	**2006**	2005	2004
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Change in fair value of long-term debt due to interest rate swaps	**$ ---**	$ (7.8)	$ 0.3
Power plant long-term service agreement	**---**	---	6.0
Issuance of common stock	**---**	---	2.2
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $5.4, $2.2, $1.7)	**$ 85.5**	$ 95.9	$ 85.2
Income taxes (net of income tax refunds)	**122.7**	42.0	37.4

10. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2006**	2005	2004
Provision (Benefit) for Current Income Taxes from Continuing Operations			
Federal	**$ 96.0**	$ 43.0	$ 19.3
State	**(7.4)**	5.0	2.2
Total Provision for Current Income Taxes from Continuing Operations	**88.6**	48.0	21.5
Provision for Deferred Income Taxes, net from Continuing Operations			
Federal	**35.4**	26.4	50.4
State	**1.9**	---	4.3
Total Provision for Deferred Income Taxes, net from Continuing Operations	**37.3**	26.4	54.7
Deferred Federal Investment Tax Credits, net	**(5.0)**	(5.1)	(5.2)
Income Taxes Relating to Other Income and Deductions	**(0.4)**	(0.7)	2.4
Total Income Tax Expense from Continuing Operations	**$ 120.5**	$ 68.6	$ 73.4

The Company files consolidated income tax returns. Income taxes are allocated to each affiliate based on its separate taxable income or loss. Federal investment tax credits on electric utility property have been deferred and are being amortized to income over the life of the related property. The Company continues to amortize its federal investment tax credits on a ratable basis throughout the year. This ratable amortization results in a larger percentage reconciling item related to these credits during the first quarter when the Company historically experiences decreased book income. The following schedule reconciles the statutory federal tax rate to the effective income tax rate:

Year ended December 31	**2006**	2005	2004
Statutory federal tax rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	**2.8**	1.5	2.0
Amortization of net unfunded deferred taxes	**0.7**	1.0	1.0
Tax credits, net	**(1.4)**	(2.2)	(2.4)
ESOP dividends	**(0.9)**	(1.8)	---
Medicare Part D subsidy	**(0.7)**	(1.2)	---
Excess deferred taxes (A)	**---**	(2.3)	---
Other	**(0.7)**	(0.1)	(1.5)
Effective income tax rate as reported	**34.8%**	29.9%	34.1%

(A) During 2005, the Company performed a detailed analysis of all deferred tax assets and liabilities. In connection with this analysis, it was determined that an excess liability existed. The removal of this excess liability caused a permanent difference in the effective tax rate for 2005 of approximately 2.3 percent.

In connection with the filing in the third quarter of 2003 of the Company s consolidated income tax returns for 2002, OG&E elected to change its tax method of accounting related to the capitalization of costs for self-constructed assets to another method prescribed in the Income Tax regulations. The accounting method change was for income tax purposes only. For financial accounting purposes, the only change was recognition of the impact of the cash flow generated by accelerating income tax deductions. This was reflected in the financial statements as a switch from current income taxes payable to deferred income taxes payable. This tax accounting method change resulted in a one-time catch-up deduction for costs previously capitalized under the prior method, resulting in a consolidated tax net operating loss for 2002. This tax net operating loss eliminated the Company s current federal and state income tax liability for 2002 and 2003 and all estimated payments made for 2002 were refunded. The Company received federal and state income tax refunds of approximately $50.8 million during 2003 related to this tax accounting method change.

During 2005, new guidelines were issued by the Internal Revenue Service (IRS) related to the change in the method of accounting used to capitalize costs for self-construction discussed above. The Company s current IRS examination process, which was completed in the second quarter of 2006, identified this change in method of accounting as an issue under examination. As a result of their examination, the IRS disagreed with the change OG&E made in 2002 and determined that OG&E should change its tax method of accounting for the capitalization of costs for self-constructed assets to another method prescribed in the Income Tax regulations. The Company filed a formal protest with the IRS on July 21, 2006 and requested a hearing with the IRS to review the IRS s determination that the tax accounting method OG&E elected in 2002 was not appropriate. On August 17, 2006, the Company made a deposit with the IRS in anticipation that a portion of prior year deductions will be disallowed. The deposit enabled OG&E to cease accruing interest effective August 17, 2006. The impact of this matter on future cash flows is uncertain but could be material. The Company cannot predict either the final outcome or the timing of the resolution of this matter. During 2005 and 2006, OG&E recorded approximately $3.5 million in additional interest expense related to income taxes as a result of a potential adjustment. This amount is included in Interest on Short-Term Debt and Other Interest Charges in the Consolidated Statements of Income.

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

The deferred tax provisions, set forth above, are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by OG&E. The components of Accumulated Deferred Taxes at December 31, 2006 and 2005, respectively, are as follows:

December 31 *(In millions)*	**2006**	2005
Current Accumulated Deferred Tax Assets		
Accrued vacation	**$ 6.2**	$ 6.3
Uncollectible accounts	**1.8**	1.4
Capitalized indirect construction costs	**1.7**	1.7
Provision for rate refund	**0.5**	2.7
Other	**0.4**	2.2
Total Current Accumulated Deferred Tax Assets	**$ 10.6**	$ 14.3
Non-Current Accumulated Deferred Tax Liabilities		
Accelerated depreciation and other property related differences	**$ 816.8**	$ 826.4
Regulatory asset	**95.2**	---
Income taxes refundable to customers, net	**16.7**	12.7
Bond redemption-unamortized costs	**6.5**	6.9
Other	**19.3**	0.7
Total Non-Current Accumulated Deferred Tax Liabilities	**954.5**	846.7
Non-Current Accumulated Deferred Tax Assets		
Company pension plan	**(26.2)**	(13.6)
Postretirement medical and life insurance benefits	**(55.5)**	(15.3)
Deferred federal investment tax credits	**(7.0)**	(8.6)
Other	**(6.6)**	(2.1)
Total Non-Current Accumulated Deferred Tax Assets	**(95.3)**	(39.6)
Non-Current Accumulated Deferred Income Tax Liabilities, net	**$ 859.2**	$ 807.1

The Company has an Oklahoma investment tax credit carryover of approximately $3.7 million. These Oklahoma credit carryover amounts will begin expiring in the year 2017. During 2006, additional Oklahoma tax credits of approximately $5.1 million were generated by OG&E and Enogex. The Company believes that, based on current projections, the entire $8.8 million of these state tax credit amounts will be fully utilized in 2007.

11. Common Stock

In July 2005, the Company filed a Form S-3 Registration Statement to register 7,000,000 shares of the Company s common stock pursuant to the Company s Automatic Dividend Reinvestment and Stock Purchase Plan (DRIP/DSPP). Under the terms of the DRIP/DSPP, the Company may accept requests for optional investments in amounts greater than $0.1 million per year and may offer a discount of up to three percent from current market prices. This program allows the Company to sell additional common stock at a smaller discount than that normally incurred in a secondary equity offering. During the years ended December 31, 2006 and 2005, the Company purchased common stock on the open market to satisfy the common stock requirements of the DRIP/DSPP and therefore did not issue any new shares of common stock. During the year ended December 31, 2004, the Company issued 721,021 shares of common stock and 1,238,043 shares of common stock at a discount of 1.50 percent and 1.25 percent, respectively, pursuant to the DRIP/DSPP. Also, as part of the

DRIP/DSPP, the Company issued 242,003 shares of common stock at no discount during the year ended December 31, 2004.

For the years ended December 31, 2006, 2005 and 2004, respectively, there were 738,426, 606,802 and 392,686 shares of new common stock issued pursuant to the Company s Stock Incentive Plan, related to exercised stock options and payouts of earned performance units. At December 31, 2006, there were 13,010,588 shares of unissued common stock reserved for the various employee and Company stock plans.

Shareowners Rights Plan

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

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

12. Earnings Per Share

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

Year ended December 31 *(In millions)*	**2006**	2005	2004
Average Common Shares Outstanding			
Basic average common shares outstanding	**91.0**	90.3	88.0
Effect of dilutive securities:			
Employee stock options and unvested stock grants	**0.3**	0.2	0.3
Contingently issuable shares (performance units)	**0.8**	0.3	0.2
Diluted average common shares outstanding	**92.1**	90.8	88.5

For the years ended December 31, 2006, 2005 and 2004, respectively, approximately 0.1 million shares, 0.2 million shares and 0.6 million shares related to outstanding employee stock options were not included in the calculation of diluted earnings per average common share because the effect of including those shares would be anti-dilutive as the exercise price of the stock options exceeded the average common stock market price during the respective period.

13. Long-Term Debt

A summary of the Company s long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2006, the Company is in compliance with all of its debt agreements**.**

Long-Term Debt with Optional Redemption Provisions

OG&E s $125.0 million principal amount 6.65 percent Senior Notes (Senior Notes) due July 15, 2027, are repayable on July 15, 2007, at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to July 15, 2007. Only holders who submit requests for repayment between May 15, 2007 and June 15, 2007 are entitled to such repayments. In accordance with SFAS No. 6, Classification of Short-Term Obligations Expected to Be Refinanced, OG&E reclassified the Senior Notes from long-term debt due within one year to long-term debt at December 31, 2006 due to OG&E having sufficient long-term liquidity in place as a result of increasing its revolving credit agreement to $400.0 million in December 2006. Also, based on where the Senior Notes have recently traded, OG&E does not believe it is probable that this option will be exercised by the note holders.

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

SERIES	DATE DUE	AMOUNT
3.11% - 4.05%	Garfield Industrial Authority, January 1, 2025	**$ 47.0**
3.20% - 4.13%	Muskogee Industrial Authority, January 1, 2025	**32.4**
3.03% - 4.06%	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, the Company is obligated to repurchase such unremarketed Bonds. The Company has sufficient long-term liquidity to meet these obligations.

Long-term Debt Maturities

Maturities of the Company s long-term debt during the next five years consist of $3.0 million in 2007; $1.0 million in 2008 and $400.0 million in 2010. There are no maturities of the Company s long-term debt in years 2009 or 2011.

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

14. Short-Term Debt

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by loans under short-term bank facilities. The short-term debt balance was approximately $30.0 million at December 31, 2005 at a weighted-average interest rate of 4.421 percent. There was no short-term debt outstanding at December 31, 2006. In accordance with SFAS No. 6, $220.0 million of commercial paper was classified as long-term debt at December 31, 2005 as OG&E planned to refinance this amount. Subsequently, OG&E issued $220 million of long-term debt in January 2006 and repaid the outstanding commercial paper and bank borrowings. The following table shows the Company s revolving credit agreements and available cash at December 31, 2006.

Revolving Credit Agreements and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding	Weighted-Average Interest Rate	Maturity
OGE Energy Corp. (A)	$ 600.0	$ ---	---	December 6, 2011 (C)
OG&E (B)	400.0	---	---	December 6, 2011 (C)
	1,000.0	---	---	
Cash	47.9	N/A	N/A	N/A

Total	$ 1,047.9	$ ---	---

(A) This bank facility is available to back up the Company s commercial paper borrowings and to provide revolving credit borrowings. This bank facility c
(B) This bank facility is available to back up OG&E s commercial paper borrowings and to provide revolving credit borrowings. At December 31, 2006, C
(C) In December 2006, the Company and OG&E amended and restated their revolving credit agreements to total in the aggregate $1.0 billion, $600 million

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The Company s and OG&E s ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the back-up lines of credit could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrades would result in an increase in the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes.

Unlike the Company and Enogex, OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2007 and ending December 31, 2008.

15. Retirement Plans and Postretirement Benefit Plans

In September 2006, the FASB issued SFAS No. 158 which requires an employer to: (i) recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity; and (ii) to measure the fair value of the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. The requirement to initially recognize the funded status of the defined benefit postretirement plan and the disclosure requirements are effective for the year ended December 31, 2006 for the Company. The requirement to measure plan assets and benefit obligations at fair value in accordance with SFAS No. 157 as of the date of the employer s fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. SFAS No. 158 also requires additional disclosures for defined benefit pension plans and other defined benefit postretirement plans.

Defined Benefit Pension Plan

All eligible employees of the Company and participating affiliates are covered by a non-contributory defined benefit pension plan. For employees hired on or after February 1, 2000, the pension plan is a cash balance plan, under which the Company annually will credit to the employee s account an amount equal to five percent of the employee s annual compensation plus accrued interest. Employees hired prior to February 1, 2000 will receive the greater of the cash balance benefit or a benefit based primarily on years of service and the average of the five highest consecutive years of compensation during an employee s last 10 years prior to retirement, with reductions in benefits for each year prior to age 62 unless the employee s age and years of credited service equal or exceed 80.

It is the Company s policy to fund the plan on a current basis based on the net periodic SFAS No. 87, Employers Accounting for Pensions, pension expense as determined by the Company s actuarial consultants. Additional amounts may be contributed from time to time to increase the funded status of the plan. During 2006 and 2005, the Company made contributions to its pension plan of approximately $90.0 million and $32.0 million, respectively, to ensure that the pension plan maintains an adequate funded status. Such contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. In August 2006, legislation was passed that changed the funding requirement for single- and multi-employer defined benefit pension plans as discussed below. During 2007, the Company may contribute up to $50 million to its pension plan. The expected contribution to the pension plan, anticipated to be in the form of cash, is a discretionary contribution and is not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

At December 31, 2006, the projected benefit obligation and fair value of assets of the Company s pension plan and restoration of retirement income plan was approximately $585.0 million and $519.4 million, respectively, for an underfunded status of approximately $65.6 million. The above amounts have been recorded in Accrued Pension and 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 entry did not impact the results of operations in 2006 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

During 2005, the Company made contributions to the pension plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2005 of approximately $88.9 million. At December 31, 2005, the Company s projected pension benefit obligation exceeded the fair value of the pension plan assets by approximately $154.6 million. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87 required the recognition of an additional minimum liability in the amount of approximately $181.4 million at December 31, 2005. The

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offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2005 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amount recorded as an intangible asset equaled the unrecognized prior service cost with the remainder recorded in Accumulated Other Comprehensive Income. The amount in Accumulated Other Comprehensive Income represents a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

In accordance with SFAS No. 88, Employer s Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization s net periodic pension cost. During 2006, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments to be paid to such employees upon retirement in 2006. As a result, the Company recorded a pension settlement charge for 2006 of approximately $17.1 million in the fourth quarter of 2006. The pension settlement charge did not require a cash outlay by the Company and did not increase the Company s total pension expense over time, as the charge was an acceleration of costs that otherwise would have been recognized as pension expense in future periods. OG&E s Oklahoma jurisdictional portion of this charge was recorded as a regulatory asset (see Note 1 for a further discussion).

Pension Plan Costs and Assumptions

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the Pension Protection Act) into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Among other things, it introduces a new funding requirement for single- and multi-employer defined benefit pension plans, provides legal certainty on a prospective basis for cash balance and other hybrid plans and addresses contributions to defined contribution plans, deduction limits for contributions to retirement plans and investment advice provided to plan participants. The Company is currently analyzing the impact of the Pension Protection Act on its pension plans.

Plan Investments, Policies and Strategies

The pension plan s assets consist primarily of investments in mutual funds, U.S. Government securities, listed common stocks and corporate debt. The following table shows, by major category, the percentage of the fair value of the plan assets held at December 31, 2006 and 2005:

December 31	**2006**	2005
Equity securities	**64 %**	59 %
Debt securities	**34 %**	36 %
Other	**2 %**	5 %
Total	**100 %**	100 %

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

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

Asset Class	Target Allocation	Minimum	Maximum
Domestic Equity	30 %	--- %	60 %
Domestic Mid-Cap Equity	10 %	--- %	10 %
Domestic Small-Cap Equity	10 %	--- %	10 %
International Equity	10 %	--- %	10 %
Fixed Income Domestic	38 %	30 %	70 %
Cash	2 %	--- %	5 %

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

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

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Asset Class	**Comparative Benchmark(s)**
Fixed Income	Lehman Aggregate Index
Equity Index	S&P 500 Index
Value Equity	Russell 1000 Value Index Short-term
	S&P 500 Index Long-term
Growth Equity	Russell 1000 Growth Index Short-term
	S&P 500 Index Long-term
Mid-Cap Equity	S&P 400 Midcap Index
Small-Cap Equity	Russell 2000 Index
International Equity	Morgan Stanley Capital International Europe, Australia and Far East Index

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

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

For all domestic equity investment managers, no more than eight percent (five percent for mid-cap and small-cap equity managers) can be invested in any one stock at the time of purchase and no more than 16 percent (10 percent for mid-cap and small-cap equity managers) after accounting for price appreciation. A minimum of 95 percent of the total assets of an equity manager s portfolio must be allocated to the equity markets. Options or financial futures may not be purchased

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unless prior approval of the Committee is received. The purchase of securities on margin is prohibited as is securities lending. Private placement or venture capital may not be purchased. All interest and dividend payments must be swept on a daily basis into a short-term money market fund for re-deployment. The purchase of any of the Company s equity, debt or other securities is prohibited. The purchase of equity or debt issues of the portfolio manager s organization is also prohibited. The aggregate positions in any company may not exceed one percent of the fair market value of its outstanding stock.

Restoration of Retirement Income Plan

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

Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members (postretirement benefits). Regular, full-time, active employees hired prior to February 1, 2000, whose age and years of credited service total or exceed 80 or have attained age 55 with 10 years of vesting service at the time of retirement are entitled to these postretirement benefits. Employees hired on or after February 1, 2000, are not entitled to postretirement medical benefits but are entitled to postretirement life insurance benefits. Eligible retirees must contribute such amount as the Company specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. OG&E charges to expense the SFAS No. 106, Employers Accounting for Postretirement Benefits other than Pensions, costs and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

At December 31, 2006, the accumulated postretirement benefit obligation and fair value of assets of the Company s postretirement benefit plans was approximately $225.4 million and $74.0 million, respectively, for an underfunded status of approximately $151.4 million. The above amounts have been recorded in Accrued Pension and 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 entry did not impact the results of operations in 2006 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

The details of the funded status of the pension plan (including the restoration of retirement income plan) and the postretirement benefit plans and the amounts included in the Consolidated Balance Sheets are as follows:

Obligations and Funded Status

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 *(In millions)*	**2006**	2005	**2006**	2005

Change in Benefit Obligation				
Beginning obligations	**$ (594.0)**	$ (548.2)	**$ (208.2)**	$ (192.3)
Service cost	**(20.4)**	(19.1)	**(3.7)**	(3.2)
Interest cost	**(30.8)**	(30.3)	**(11.9)**	(10.5)
Participants contributions	**---**	---	**(5.0)**	(3.9)
Actuarial losses	**(14.9)**	(38.9)	**(12.1)**	(12.0)
Benefits paid	**75.1**	42.5	**15.5**	13.7
Ending obligations	**(585.0)**	(594.0)	**(225.4)**	(208.2)
Change in Plans Assets				
Beginning fair value	**439.4**	424.9	**67.2**	64.0
Actual return on plans assets	**64.7**	23.9	**8.4**	4.6
Employer contributions	**90.4**	33.1	**8.9**	8.4
Participants contributions	**---**	---	**5.0**	3.9
Benefits paid	**(75.1)**	(42.5)	**(15.5)**	(13.7)
Ending fair value	**519.4**	439.4	**74.0**	67.2
Funded status at end of year	**$ (65.6)**	$ (154.6)	**$ (151.4)**	$ (141.0)

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Incremental Effect of Applying SFAS No. 158 on Individual Line Items in the Consolidated Balance Sheet at December 31, 2006

December 31 *(In millions)*	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
Regulatory asset SFAS 158	$ ---	$ 231.1	$ 231.1
Intangible asset unamortized prior service cost	3.2	(3.2)	---
Prepaid benefit obligation	129.7	(129.7)	---
Total deferred charges and other assets	237.0	98.2	335.2
Accrued pension and benefit obligations:			
Defined pension plan	7.5	58.1	65.6
Defined postretirement benefit plans	57.9	93.5	151.4
Accumulated deferred income taxes	881.6	(22.4)	859.2
Total deferred credits and other liabilities	1,149.7	129.2	1,278.9
Accumulated other comprehensive loss	3.0	(31.0)	(28.0)
Total stockholders equity	1,634.8	(31.0)	1,603.8

Amounts recognized in the Consolidated Balance Sheets consist of:

December 31 *(In millions)*	Pension Plan and Restoration of Retirement Income Plan 2005	Postretirement Benefit Plans 2005
Prepaid benefit obligation	$ 90.2	$ ---
Accrued pension and benefit obligations	(182.8)	(43.3)
Intangible asset - unamortized prior service cost	32.8	---
Accumulated deferred tax asset	57.5	---
Accumulated other comprehensive loss, net of tax	91.2	---
Net amount recognized	$ 88.9	$ (43.3)

Net Periodic Benefit Cost

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31*(In millions)*	**2006**	2005	2004	**2006**	2005	2004
Service cost	**$ 20.4**	$ 19.1	$ 16.9	**$ 3.7**	$ 3.2	$ 3.0
Interest cost	**30.8**	30.3	29.7	**11.9**	10.5	11.1
Return on plan assets	**(38.4)**	(34.2)	(31.6)	**(5.6)**	(5.5)	(5.5)
Amortization of transition obligation	**---**	---	---	**2.7**	2.7	2.7
Amortization of net loss	**16.7**	14.7	11.9	**8.7**	5.0	4.9
Amortization of recognized prior service cost	**5.9**	6.3	6.3	**2.1**	2.1	2.1
Settlement (A)	**17.1**	---	---	**---**	---	---
Net periodic benefit cost (B)	**$ 52.5**	$ 36.2	$ 33.2	**$ 23.5**	$ 18.0	$ 18.3

(A) Approximately $13.7 million of the $17.1 million settlement charge relates to OG Es Oklahoma jurisdictional portion, which has been recorded as a regulatory asset (see Note 1 for a further discussion).

(B) The capitalized portion of the net periodic pension benefit cost was approximately $7.6 million, $9.3 million and $8.4 million at December 31, 2006, 2005 and 2004, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $5.0 million, $4.7 million and $5.0 million at December 31, 2006, 2005 and 2004, respectively.

Rate Assumptions

	Pension Plan			Postretirement Benefit Plans		
Year ended December 31	**2006**	2005	2004	**2006**	2005	2004
Discount rate	**5.75%**	5.50%	5.75%	**5.75%**	5.50%	5.75%
Rate of return on plans assets	**8.50%**	8.50%	8.75%	**8.50%**	8.50%	8.75%
Compensation increases	**4.50%**	4.50%	4.50%	**4.50%**	4.50%	4.50%
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**9.00%**	9.00%	10.00%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2012**	2011	2010

N/A - not applicable

The overall expected rate of return on plan assets assumption remained 8.50 percent in 2005 and 2006 in determining net periodic benefit cost. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the pension plan or postretirement benefit plans. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans current and expected asset allocation.

The Company expects to pay benefits related to its pension plan and restoration of retirement income plan of approximately $61.8 million in 2007, $64.2 million in 2008, $65.3 million in 2009, $64.5 million in 2010, $67.4 million in 2011 and an aggregate of $312.8 million in years 2012 to 2016. These expected benefits were 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.

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 eight percent in 2007 with the rates decreasing in subsequent years by one percentage point per year through 2010. 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)*	**2006**	2005	2004
Effect on aggregate of the service and interest cost components	**$ 2.2**	$ 1.8	$ 1.9
Effect on accumulated postretirement benefit obligations	**29.2**	26.9	24.2

ONE-PERCENTAGE POINT DECREASE

Year ended December 31 *(In millions)*	**2006**	2005	2004
Effect on aggregate of the service and interest cost components	**$ 1.8**	$ 1.5	$ 1.5
Effect on accumulated postretirement benefit obligations	**24.0**	22.0	19.8

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Medicare Act). The Medicare Act expanded Medicare to include, for the first time, coverage for prescription drugs. In May 2004, the FASB issued FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. FAS 106-2 provided guidance on the accounting for the effects of the Medicare Act for employers that sponsor postretirement heath care plans that provide prescription drug benefits. FAS 106-2 also required those employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. The Company adopted this new standard effective July 1, 2004 with retroactive application to the date of the Medicare Act s enactment. Management expects that the accumulated plan benefit obligation (APBO) for the Company with respect to its postretirement medical plan will be reduced by approximately $39.7 million as a result of savings to the Company with respect to its postretirement medical plan resulting from the Medicare Act provided subsidy, which will reduce the Company s costs for its postretirement medical plan by approximately $6.5 million annually. The $6.5 million in annual savings is comprised of a reduction of approximately $3.8 million from amortization of the $39.7 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $2.2 million and a reduction in the service cost due to the subsidy of approximately $0.5 million.

The Company expects to pay gross benefits payments related to its postretirement benefit plans, including prescription drug benefits, of approximately $12.1 million in 2007, $12.6 million in 2008, $13.6 million in 2009, $14.6 million in 2010, $15.6 million in 2011 and an aggregate of $89.2 million in years 2012 to 2016. The Company expects to receive federal subsidy receipts provided by the Medicare Act of approximately $1.1 million in 2007, $1.3 million in 2008, $1.4 million in 2009, $1.6 million in 2010, $1.7 million in 2011 and an aggregate of $10.2 million in years 2012 to 2016. The Company did not receive any federal subsidy receipts in 2006.

Defined Contribution Plan

The Company provides a defined contribution savings plan. Each regular full-time employee of the Company or a participating affiliate is eligible to participate in the plan immediately. All other employees of the Company or a participating affiliate are eligible to become participants in the plan after completing one year of service as defined in the plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the plan, for that pay period. Contributions of the first six percent of compensation are called Regular Contributions and any contributions over six percent of compensation are called Supplemental Contributions. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as Catch-Up Contributions, subject to the limitations of the Code. The Company contributes to the Plan each pay period on behalf of each participant an amount equal to 50 percent of the participant s Regular Contributions for participants whose employment or re-employment date, as defined in the plan, occurred before February 1, 2000 and who have less than 20 years of service, as defined in the plan, and an amount equal to 75 percent of the participant s Regular Contributions for participants whose employment or re-employment date occurred before February 1, 2000 and who have 20 or more years of service. For participants whose employment or re-employment date occurred on or after February 1, 2000, the Company shall contribute 100 percent of the Regular Contributions deposited during such pay period by such participant. No Company contributions are made with respect to a participant s Supplemental Contributions, Catch-Up Contributions, or with respect to a participant s Regular Contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. The Company s contribution which is initially allocated for investment to the OGE Energy Corp. Common Stock Fund may be made in shares of the Company s common stock or in cash which is used to invest in the Company s common stock. Once made, the Company s contribution may be reallocated, at any time, by participants to other available investment options. The Company contributed approximately $6.8 million, $6.7 million and $6.2 million during 2006, 2005 and 2004, respectively, to the defined contribution plan.

Deferred Compensation Plan

The Company provides a deferred compensation plan. The plan s primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees defined contribution plan contributions as well as offering this plan to be competitive in the marketplace.

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of bonus awards; or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the defined contribution plan with such deferrals to start when maximum deferrals to the qualified defined contribution plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors meeting fees and annual retainers. The Company matches employee (but not non-employee director) deferrals to provide for the match that would have been made under the defined contribution plan had such deferrals been made under that plan without regard to the statutory limitations on elective deferrals and matching contributions applicable to the defined contribution plan. In addition, the Benefits Committee may award discretionary employer contribution credits to a participant under the plan. The Company accounts for the contributions related to the Company s executive officers in this plan as Accrued Pension and 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

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for a sufficient level of benefits under the Company s pension plan. The supplemental executive retirement plan is intended to be an unfunded plan and not subject to the benefit limits imposed by the Code.

16. Report of Business Segments

The Company s Electric Utility operations are conducted through OG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy. The Company s Natural Gas Pipeline operations are conducted through Enogex. Enogex is engaged in the transportation and storage of natural gas, the gathering and processing of natural gas and the marketing of natural gas. Other Operations for the years ended December 31, 2006 and 2005 primarily includes unallocated corporate expenses, interest expense on commercial paper and interest expense on long-term debt. Other Operations for the year ended December 31, 2004 primarily includes unallocated corporate expenses, interest expense to unconsolidated affiliate and interest expense on commercial paper. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. The following tables summarize the results of the Company s business segments for the years ended December 31, 2006, 2005 and 2004.

2006 *(In millions)*	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
Operating revenues	**$ 1,745.7**	**$ 2,367.8**	**$ ---**	**$ (107.9)**	**$ 4,005.6**
Cost of goods sold	**950.0**	**2,060.4**	**---**	**(107.9)**	**2,902.5**
Gross margin on revenues	**795.7**	**307.4**	**---**	**---**	**1,103.1**
Other operation and maintenance	**316.5**	**110.0**	**(9.9)**	**---**	**416.6**
Depreciation	**132.2**	**42.3**	**6.9**	**---**	**181.4**
Impairment of assets	**---**	**0.3**	**---**	**---**	**0.3**
Taxes other than income	**53.1**	**16.0**	**3.0**	**---**	**72.1**
Operating income	**293.9**	**138.8**	**---**	**---**	**432.7**
Interest income	**1.9**	**11.1**	**4.4**	**(11.2)**	**6.2**
Allowance for equity funds used during construction	**4.1**	**---**	**---**	**---**	**4.1**
Other income	**4.0**	**7.7**	**4.6**	**---**	**16.3**
Other expense	**9.7**	**0.3**	**6.7**	**---**	**16.7**
Interest expense	**60.1**	**31.8**	**15.3**	**(11.2)**	**96.0**
Income tax expense (benefit)	**84.8**	**48.0**	**(12.3)**	**---**	**120.5**
Income (loss) from continuing operations	**149.3**	**77.5**	**(0.7)**	**---**	**226.1**
Income from discontinued operations	**---**	**36.0**	**---**	**---**	**36.0**
Net income (loss)	**$ 149.3**	**$ 113.5**	**$ (0.7)**	**$ ---**	**$ 262.1**
Total assets	**$ 3,589.7**	**$ 1,323.4**	**$ 1,968.8**	**$ (1,979.9)**	**$ 4,902.0**
Capital expenditures	**$ 411.1**	**$ 67.1**	**$ 8.4**	**$ ---**	**$ 486.6**

(A) Natural Gas Pipeline s operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

2006 *(In millions)*	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	**$ 225.9**	**$ 704.3**	**$ 1,941.3**	**$ (503.7)**	**$ 2,367.8**
Operating income	**$ 54.7**	**$ 79.8**	**$ 4.3**	**$ ---**	**$ 138.8**

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2005 *(In millions)*	Electric Utility (A)	Natural Gas Pipeline (B)	Other Operations	Intersegment	Total
Operating revenues	$ 1,720.7	$ 4,332.4	$ ---	$ (141.6)	$ 5,911.5
Cost of goods sold	994.2	4,090.4	---	(142.3)	4,942.3
Gross margin on revenues	726.5	242.0	---	0.7	969.2
Other operation and maintenance	309.2	96.6	(10.9)	---	394.9
Depreciation	134.4	40.4	7.8	---	182.6
Taxes other than income	50.7	15.4	3.2	---	69.3
Operating income (loss)	232.2	89.6	(0.1)	0.7	322.4
Interest income	2.6	2.9	1.7	(3.7)	3.5
Other income (loss)	(2.8)	0.8	1.7	---	(0.3)
Other expense	2.5	0.3	2.7	---	5.5
Interest expense	47.2	32.6	14.2	(3.7)	90.3
Income tax expense (benefit)	52.6	20.4	(4.7)	0.3	68.6
Income (loss) from continuing operations	129.7	40.0	(8.9)	0.4	161.2
Income from discontinued operations	---	49.8	---	---	49.8
Net income (loss)	$ 129.7	$ 89.8	$ (8.9)	$ 0.4	$ 211.0
Total assets	$ 3,255.0	$ 1,680.1	$ 1,963.4	$ (1,999.6)	$ 4,898.9
Capital expenditures	$ 249.1	$ 34.7	13.4	$ ---	$ 297.2

(A) Natural Gas Pipeline s operations consist of three related business: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

(B) In January 2005, a cogeneration credit rider was implemented at OG&E as part of the Oklahoma retail customer electric rates in order to return purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration previously included in base rates to OG&E s customers. This rider resulted in the seasonal over or under collection of revenues as the rider is based on an equal monthly amount of kilowatt-hour (kwh) usage as compared to actual kwh usage. Due to the seasonal rates of OG&E s electric sales, this resulted in a temporary over collection of operating revenues in excess of the reduction in operating and maintenance expense for the first quarter of 2005 of approximately $3.4 million. In August 2005, the Company determined that OG&E s net income should not be affected by over or under collections on a temporary or permanent basis, and accordingly, any difference at that time was deferred as a regulatory asset to better reflect the purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration. Subsequent to August 2005, any over or under collections related to the cogeneration credit rider are reflected as a regulatory asset or liability.

2005 *(In millions)*	Transportation and Storage	Gathering and Processing	Marketing (C)	Eliminations	Total
Operating revenues	$ 246.4	$ 644.5	$ 3,995.3	$ (553.8)	$ 4,332.4
Operating income (loss)	$ 37.3	$ 58.5	$ (6.2)	$ ---	$ 89.6

(C) In March 2005, Enogex corrected its procedure for accounting for park and loan transactions (natural gas storage transactions) during 2004 that resulted from an incorrect change in an accounting procedure implemented during 2004. The incorrect procedure affected the timing of recognition of revenue and income from park and loan transactions and resulted in a temporary overstatement of operating revenues without the associated expense until the transaction was completed and the expense recognized. As a result of this correction, Enogex recorded a pre-tax charge of approximately $7.7 million ($4.7 million after tax or $0.05 per share) as a reduction in Operating Revenues in the Consolidated Statement of Income and a corresponding $7.7 million decrease in Current Price Risk Management Assets in the Consolidated Balance Sheet during the three months ended March 31, 2005.

2004 *(In millions)*	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
Operating revenues	$ 1,578.1	$ 3,379.9	$ ---	$ (95.4)	$ 4,862.6
Cost of goods sold	914.2	3,118.2	---	(94.7)	3,937.7
Gross margin on revenues	663.9	261.7	---	(0.7)	924.9
Other operation and maintenance	301.9	93.5	(11.2)	---	384.2
Depreciation	122.7	41.1	8.3	---	172.1
Impairment of assets	---	7.8	---	---	7.8
Taxes other than income	47.0	16.0	3.3	---	66.3
Operating income (loss)	192.3	103.3	(0.4)	(0.7)	294.5
Interest income	2.7	3.2	1.3	(2.3)	4.9
Allowance for equity funds used during construction	0.9	---	---	---	0.9
Other income	4.5	4.5	1.5	---	10.5
Other expense	2.3	0.3	2.1	---	4.7
Interest expense	37.5	32.2	23.4	(2.3)	90.8
Income tax expense (benefit)	53.0	29.4	(8.7)	(0.3)	73.4
Income (loss) from continuing operations	107.6	49.1	(14.4)	(0.4)	141.9
Income from discontinued operations	---	11.6	---	---	11.6
Net income (loss)	$ 107.6	$ 60.7	$ (14.4)	$ (0.4)	$ 153.5
Total assets	$ 3,057.7	$ 1,740.3	$ 1,717.1	$ (1,712.2)	$ 4,802.9
Capital expenditures	$ 391.2	$ 28.9	$ 8.5	$ ---	$ 428.6

(A) Natural Gas Pipeline s operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The follow

2004 *(In millions)*	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$ 249.4	$ 524.7	$ 3,056.1	$ (450.3)	$ 3,379.9
Operating income	$ 47.1	$ 46.7	$ 9.5	$ ---	$ 103.3

17. Commitments and Contingencies

Capital Expenditures

The Company s capital expenditures are estimated at approximately: 2007 $568.1 million, 2008 $838.6 million, 2009 $815.9 million, 2010 $659.9 million, 2011 $550.2 million and 2012 $436.0 million. These amounts include capital expenditures of approximately $94.0 million, $278.8 million, $285.7 million, $97.7 million and $34.1 million, respectively, in 2007 through 2011 related to the construction of the proposed Red Rock power plant as discussed in Note 18.

Operating Lease Obligations

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

Year ended December 31 *(In millions)*	2007	2008	2009	2010	2011	2012 and Beyond
Operating lease obligations						
OG&E railcars	$ 4.0	$ 3.9	$ 3.8	$ 3.7	$ 36.6	$ ---
Enogex noncancellable operating leases	2.2	1.8	1.3	1.4	1.5	0.4
Total operating lease obligations	$ 6.2	$ 5.7	$ 5.1	$ 5.1	$ 38.1	$ 0.4

Payments for operating lease obligations were approximately $7.6 million, $9.7 million and $9.7 million in 2006, 2005 and 2004, respectively.

OG&E Railcar Lease Agreement

At December 31, 2006, OG&E had a noncancellable operating lease with purchase options, covering 1,464 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 automatic fuel adjustment clauses. On December 29, 2005, OG&E entered into a new lease agreement for railcars effective February 1, 2006 with a new lessor as described below. At the end of the new lease term which is January 31, 2011, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of approximately $29.9 million. OG&E is also required to maintain the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

Public Utility Regulatory Policy Act of 1978

OG&E has entered into agreements with three qualifying cogeneration facilities having initial terms of three to 32 years. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978 (PURPA). Stated generally, PURPA and the regulations thereunder promulgated by the FERC require OG&E to purchase power generated in a manufacturing process from a qualified cogeneration facility (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. OG&E has approximately 430 MW s of QF contracts that will expire at the end of 2007, unless extended by OG&E. For one of these QF contracts, OG&E purchases 100 percent of electricity generated by the QF. For the other QF contract, OG&E can purchase up to 17 percent of electricity generated by the QF. In addition, effective September 1, 2004, OG&E entered into a new 15-year power purchase agreement for 120 MW s with Powersmith Cogeneration Project, L.P. (PowerSmith) in which OG&E purchases 100 percent of electricity generated by PowerSmith.

During 2006, 2005 and 2004, OG&E made total payments to cogenerators of approximately $162.6 million, $183.8 million and $203.5 million, respectively, of which approximately $94.9 million, $95.5 million and $155.3 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as Cost of Goods Sold. The future minimum capacity payments under the contracts are approximately: 2007 $97.6 million, 2008 $96.1 million, 2009 $94.4 million, 2010

$92.6 million and 2011 $90.6 million. The minimum capacity payment amounts for 2008 through 2011 assume OG&E elects to extend certain cogeneration contracts, which otherwise expire at the end of 2007.

Fuel Minimum Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of approximately $195.1 million, $163.5 million and $166.5 million for the years ended December 31, 2006, 2005 and 2004, respectively. OG&E has entered into purchase commitments of necessary fuel supplies of approximately: 2007 $198.0 million, 2008 $114.1 million, 2009 $105.9 million, 2010 $107.7 million, 2011 - $65.4 million and 2012 and Beyond $23.4 million.

Natural Gas Units

In October 2006, OG&E issued and completed a request for proposal (RFP) for gas supply purchases for periods that began in November 2006 through March 2007, which accounted for approximately eight percent of its projected 2007 natural gas requirements. All of these contracts are tied to various gas price market indices and will expire in 2007. OG&E s remaining 2007 natural gas requirements will be met with additional RFP s in early to mid-2007. OG&E will meet additional natural gas requirements with monthly and daily purchases as required.

Purchased Power

In October 2006, OG&E issued an RFP for firm economy energy purchases during the summer of 2007 and expects to select a supplier in early 2007. Also, in early 2007, OG&E expects to issue an RFP for capacity and/or firm energy purchases for the summer periods of 2008 through 2010 and expects to select a supplier by the early summer of 2007.

Natural Gas Measurement Cases

United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E. (United States District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al. (United States District Court for the Eastern District of Louisiana, Case No. 97-2089; United States District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with Plaintiff s complaint, which is a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleges: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and British thermal unit (Btu) content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys fees.

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

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

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

On October 20, 2006, the District Court of Wyoming ruled on Grynberg s appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex Services Corp., Transok, Inc. and OG&E, for lack of subject matter jurisdiction. Judgment was entered on November 17, 2006 and Grynberg filed his notice of appeal with the District Court of Wyoming. The defendants filed motions for attorneys fees regarding issues of liability and Rule 11 motions on January 8, 2007. The defendants also filed for other legal costs on December 18, 2006. A hearing on these motions is currently scheduled for April 24, 2007. Grynberg has also filed appeals with the Tenth Circuit Court of Appeals. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Will Price (Price I) On September 24, 1999, various subsidiaries of the Company were served with a class action petition filed in United States District Court, State of Kansas by Quinque Operating Company and other named plaintiffs, alleging mismeasurement of natural gas on non-federal lands. On April 10, 2003 the Court entered an order denying class certification. On May 12, 2003, Plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended petition and the court granted the motion on July 28, 2003. In this amended petition, OG&E and Enogex Inc. were omitted from the case. Two subsidiaries of Enogex remain as defendants. The Plaintiffs amended petition alleges that approximately 60 defendants, including two Enogex subsidiaries, have improperly measured natural gas. The amended petition reduces the claims to: (1) mismeasurement of volume only; (2) conspiracy, unjust enrichment and accounting; (3) a putative Plaintiffs class of only royalty owners; and (4) gas measured in three specific states. A hearing on class certification issues was held April 1, 2005. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Will Price (Price II) On May 12, 2003, the Plaintiffs (same as those in Price I above) filed a new class action petition (Price II) in the District Court of Stevens County, Kansas, relating to wrongful Btu analysis against natural gas pipeline owners and operators, naming the same defendants as in the amended petition of the Price I case. Two Enogex subsidiaries were served on August 4, 2003. The Plaintiffs seek to represent a class of only royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The class action petition alleges improper analysis of gas heating content. In all other respects, the Price II petition appears to be the same as the amended petition in Price I. A hearing on class certification issues was held April 1, 2005. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Pipeline Rupture

On May 10, 2005, a natural gas pipeline rupture occurred on an Enogex facility within the ANR Pipeline, Inc. plant site in Custer County, near Clinton, Oklahoma, resulting in an explosion and fire. No injuries were reported as a result of the incident. It is anticipated that any third party damages related to this incident will not be material to the Company as they will be covered by insurance following payment of the deductible, which deductible has been accrued in the Company s Consolidated Financial Statements.

Farris Buser Litigation

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

Osterhout Litigation

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

Supreme Court asking the court to direct the trial court to dismiss the class action suit. At the present time, OG&E believes that this case is without merit and intends to continue vigorously defending this case.

Calpine Corporation Bankruptcy

Calpine Corporation, Calpine Energy Services, L.P., and several other affiliates (collectively Calpine) voluntarily filed for Chapter 11 bankruptcy protection from creditors on December 20, 2005 (Case No. 05-60200 (BRL)) United States Bankruptcy Court, S.D. of New York. Enogex provides natural gas transportation services pursuant to long-term contracts to two Calpine-owned power generation plants in Oklahoma. Calpine is continuing to operate the plants and request services pursuant to the contracts. The total unpaid amount due to Enogex from Calpine is approximately $0.3 million which has been fully reserved on the Company s books.

A Calpine-owned power generation plant in Oklahoma is contractually obligated to provide capacity and energy to OG&E. The Calpine plant also pays, through the Southwest Power Pool (SPP), for transmission services provided to OG&E. OG&E expects both arrangements to remain in effect; however, whether Calpine in its bankruptcy proceedings will ultimately reject these agreements with OG&E is unknown.

Potential Collateral Requirements

At December 31, 2006 in the event Moody s or Standard & Poor s were to lower Enogex s senior unsecured debt rating to a below investment grade rating, Enogex would be required to post approximately $3.3 million of collateral to satisfy its obligation under its financial and physical contracts.

Environmental Laws and Regulations

Approximately $16.5 million and $97.5 million, respectively of the Company s capital expenditures budgeted for 2007 and 2008 are to comply with environmental laws and regulations. The Company s management believes that all of its operations are in substantial compliance with present federal, state and local environmental standards. It is estimated that the Company s total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $84.4 million during 2007 as compared to approximately $60.1 million in 2006. The Company continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position itself in a competitive market.

OG&E

Air

On March 15, 2005, the Environmental Protection Agency (EPA) issued the Clean Air Mercury Rule (CAMR) to limit mercury emissions from coal-fired boilers. On May 31, 2006, the EPA issued a ruling which amended and clarified minor portions of the CAMR. The CAMR is currently subject to legal challenges. The CAMR requires reductions in mercury in two phases, Phase I beginning in 2010 and Phase II in 2018. The CAMR is based on the cap and trade program that will allow utilities to purchase mercury allowances (if available) rather than reduce emissions. It is anticipated that OG&E will need to obtain allowances or reduce its mercury emissions in Phase II by approximately 70 percent. The CAMR requires each state to adopt the requirements of the federal rule into a state implementation plan. However, the CAMR does not preclude states from developing more stringent mercury reduction requirements. The state of Oklahoma has proposed to incorporate the EPA s CAMR, along with the proposed mercury allowance allocations, into the state implementation program. OG&E is currently participating in the state rulemaking process and anticipates the rulemaking to be completed by the end of 2007. Because rulemaking is in progress, the cost to install any mercury controls is uncertain at this time but is expected to be significant to meet Phase II requirements in 2018. The state implementation plan will also require continuous monitoring of mercury emissions from OG&E s coal-fired boilers beginning in 2009. The cost of the monitoring equipment is estimated at approximately $7.9 million which is expected to be incurred during the years 2007 and 2008. However, the cost to comply with the CAMR monitoring requirements will be in addition to the cost of other emissions monitoring that is already in place pursuant to Title IV of the Clean Air Act Amendments of 1990.

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

In September 2005, the Oklahoma Department of Environmental Quality (ODEQ) informally notified affected utilities that they would be required to perform a study to determine their impact on visibility in Federal Class I areas. Affected utilities are those which have Best Available Retrofit Technology (BART) eligible sources (sources built between 1962 and 1977). For OG&E these include various generating units at various generating stations. Regulations, however, allow an owner or operator of a BART-eligible source to request and obtain a waiver from BART if modeling shows no significant impact on visibility in nearby Class I areas. Therefore, OG&E initiated a preliminary modeling study that was completed in July 2006. Because the preliminary results indicated a significant impact from OG&E s Sooner, Muskogee, Seminole and Horseshoe Lake generating stations on visibility in Class I areas in both Oklahoma and Arkansas, more detailed modeling is being performed. Based on results of modeling for the Seminole and Horseshoe Lake generating stations, OG&E submitted an application for waiver to the ODEQ on December 1, 2006. The ODEQ and the EPA approvals are required for any waiver; it is not known at this time whether approval will be granted. The ODEQ made a preliminary determination to accept the application for Horseshoe Lake and reject the application for Seminole. OG&E is continuing to discuss the Seminole application with the ODEQ.

OG&E is currently evaluating various control strategies for its generating units. Proposed compliance determinations for affected units must be submitted to the ODEQ by March 30, 2007. The ODEQ will then incorporate OG&E s, as well as other industry s compliance plans, into the state implementation plan which will then be submitted to the EPA. Once the EPA approves the plan, OG&E will have five years to institute any required reductions. OG&E is in the process of determining the extent of pollution control equipment needed to comply with the regulations. OG&E plans to spend approximately $5.4 million during 2007 related to the regional haze project. OG&E currently estimates that it could be required to spend approximately $600 million over a five-year period to install certain equipment such as scrubbers and low nitrogen oxide (NOX) burners at its generating stations. However, this amount could increase or decrease substantially based on the interpretation of the requirements by the ODEQ and the EPA, the availability of alternative control measures to achieve more cost effective visibility improvements, the availability of materials, labor force and the specific design criteria for OG&E s generating units. OG&E expects that any necessary environmental expenditures will qualify as part of a pre-approval plan to handle state and federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E s retail customers under House Bill 1910, which was enacted into law in May 2005.

Currently, the EPA has designated Oklahoma in attainment with the ambient standard for ozone. However, future elevated readings could lead to redesignation of these areas as non-attainment. Both Tulsa and Oklahoma City have entered into an Early Action Compact with the EPA whereby voluntary measures will be enacted to reduce ozone. This compact expires in December 2007. However, the EPA has proposed continuation through a similar program called Ozone Flex, which both Oklahoma City and Tulsa expect to participate. If either Tulsa or Oklahoma City became non-attainment, reductions in nitrogen oxides emissions from OG&E s generating facilities may be required.

On April 25, 2005, the EPA published a finding that all 50 states failed to submit the interstate pollution transport plans required by the Clean Air Act as a result of the adoption of the revised ambient ozone and fine particle standards. Failure to submit these implementation plans began a two-year timeframe, starting on May 25, 2005, during which states must submit a demonstration to the EPA that they do not affect air quality in downwind states. Earlier in 2005 it was unclear whether this could be accomplished by the state of Oklahoma and it was previously reported that there may be future significant expenditures required by OG&E if Oklahoma was determined to impact the air quality in downwind states. However, recent communications with the state of Oklahoma have affirmed that they have completed the demonstration that they do not affect air quality in downwind states and are on target to submit it to the EPA by the May 25, 2007 deadline. Therefore, there should be no significant impact to OG&E as a result of the April 25, 2005 finding.

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

The 1990 Clean Air Act includes an acid rain program to reduce sulfur dioxide (SO_2) emissions. Reductions were obtained through a program of emission (release) allowances issued by the EPA to power plants covered by the acid rain program. Each allowance is worth one ton of SO_2 released from the smokestack. Plants may only release as much SO_2 as they have allowances. Allowances may be banked and traded or sold nationwide. Beginning in 2000, OG&E became subject to more stringent SO_2 emission requirements in Phase II of the acid rain program. These lower limits had no significant financial impact due to OG&E s earlier decision to burn low sulfur coal. In 2006, OG&E s SO2 emissions were well below the allowable limits.

The EPA allocated SO2 allowances to OG&E starting in 2000 and OG&E started banking allowances in 2001. In February 2006, OG&E sold 6,312 allowances for approximately $8.9 million. See Note 18 for a discussion of the SO2 allowance joint filing made in February 2006 which discusses how the proceeds from the sale of SO2 allowances will be shared between OG&E and its customers for any sales after December 31, 2005.

With respect to the NOX regulations of the acid rain program, OG&E committed to meeting a 0.45 lbs/million British thermal unit (MMBtu) NOX emission level in 1997 on all coal-fired boilers. As a result, OG&E was eligible to exercise its option to extend the effective date of the lower emission requirements from the year 2000 until 2008. OG&E s average NOX emissions from its coal-fired boilers for 2006 were approximately 0.33 lbs/MMBtu. The regulations require that OG&E achieve a NOX emission level of 0.40 lbs/MMBtu for these boilers beginning in 2008. Further reductions in NOX emissions could be required if the ODEQ determines that such NOX emissions are contributing to regional haze or that OG&E s facilities impact the air quality of the Tulsa or Oklahoma City metropolitan areas, or if Oklahoma becomes non-attainment with the fine particulate standard. Any of these scenarios would require significant capital and operating expenditures.

The ODEQ Clean Air Act Amendment Title V permitting program was approved by the EPA in March 1996. By March of 1997, OG&E had submitted all required permit applications. As of December 31, 2006, OG&E had received Title V permits for all of its generating stations. Since these permits require renewal every five years, OG&E has begun the renewal process for some of its generating stations. Air permit fees for generating stations were approximately $0.6 million in 2006. The fees for 2007 are estimated to be approximately the same as in 2006.

There have been a variety of unsuccessful legislative and litigation efforts to force mandatory control of utility emissions that allegedly contribute to climate change. If legislation is passed in the future requiring mandatory carbon dioxide emission reductions to address climate change, this could have a tremendous impact on all coal-fired electric utilities, including OG&E s operations by requiring OG&E to significantly reduce the use of coal as a fuel source.

Waste

OG&E has sought and will continue to seek, new pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2006, OG&E obtained refunds of approximately $2.0 million from its recycling efforts. This figure does not include the additional savings gained through the reduction and/or avoidance of disposal costs and the reduction in material purchases due to the reuse of existing materials. Similar savings are anticipated in future years.

Water

OG&E had one Oklahoma Pollutant Discharge Elimination System (OPDES) permit approved during 2006 and has one other OPDES permit renewal pending. OG&E expects that this permit will be issued during the first or second quarter of 2007. OG&E expects that this permit, when issued, will continue to be reasonable in its requirements, allow operational flexibility and provide reductions in operating costs. Additionally, OG&E filed an application with the state of Oklahoma during 2006 for a new wastewater discharge permit for one of its facilities. OG&E expects that the wastewater discharge permit for this facility will be issued in the first or second quarter of 2007.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the best available technology for minimizing environmental impacts. The EPA 316(b) rules for existing facilities became effective July 23, 2004. OG&E has engaged a consultant who has developed the required documentation for four OG&E facilities. These documents were submitted to the state agency on December 7, 2005 for review and approval. OG&E has also provided the state of Oklahoma with information and requests that, if approved by the state, may reduce the impact of the 316(b) rules on OG&E because if OG&E s position is approved, three of the four OG&E facilities would not be required to comply with the 316(b) rules. Depending on the ultimate analysis and final determinations regarding the 316(b) rules, capital and/or operating costs may increase at any affected OG&E generating facility. On January 25, 2007, a federal court reversed and remanded portions of the 316(b) rules to the EPA. The existing rules remain in effect while the EPA is considering how to respond to the court decision. It is not clear what changes, if any, the EPA will make to the rules or how those changes may affect OG&E.

Enogex

The construction and operation of pipelines, plants and other facilities for transporting, processing, compressing or storing natural gas and other products may be subject to federal, state and local environmental laws and regulations, including those that can impose obligations to remediate hazardous substances at locations where Enogex operates. In most instances, the applicable regulatory requirements relate to water and air pollution control or solid waste management measures. Appropriate governmental authorities may enforce these laws and regulations with a variety of civil and criminal enforcement measures, including monetary penalties, assessment and remediation requirements and injunctions with respect to future compliance. Enogex may generate some materials subject to the requirements of the Federal Resource Conservation and Recovery Act and the Clean Water Act and comparable state statutes, prepares and files reports and documents pursuant to the Toxic Substance Control Act and the Emergency Planning and Community Right to Know Act and obtains permits pursuant to the Federal Clean Air Act and comparable state air statutes.

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

The Company has and will continue to evaluate the impact of its operations on the environment. As a result, contamination on Company property may be discovered from time to time.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies and income tax related items. Management consults with legal counsel and other appropriate experts to assess the claim. If, in management s opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company s Consolidated Financial Statements. Except as otherwise stated above, in Note 18 below and in Item 3 of this Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company s consolidated financial position, results of operations or cash flows.

18. Rate Matters and Regulation

Regulation and Rates

OG&E s retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E s wholesale electric tariffs, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the Department of Energy has jurisdiction over some of OG&E s facilities and operations. For the year ended December 31, 2006, approximately 87 percent of OG&E s electric revenue was subject to the jurisdiction of the OCC, nine percent to the APSC and four percent to the FERC.

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

Completed Regulatory Matters

2002 Settlement Agreement

On November 22, 2002, the OCC signed a rate order containing the provisions of the 2002 Settlement Agreement. The 2002 Settlement Agreement provided for, among other items: (i) a $25.0 million annual reduction in the electric rates of

OG&E s Oklahoma customers which went into effect January 6, 2003; (ii) recovery by OG&E, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) OG&E to acquire electric generation of not less than 400 MW (New Generation) to be integrated into OG&E s generation system; and (iv) recovery by OG&E, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through OG&E s rider for sales to other utilities and power marketers (off-system sales). Previously, OG&E had a 50/50 sharing mechanism in Oklahoma for any off-system sales. The 2002 Settlement Agreement provided that the first $1.8 million in annual net profits from OG&E s off-system sales will go to OG&E, the next $3.6 million in annual net profits from off-system sales will go to OG&E s Oklahoma customers and any net profits from off-system sales in excess of these amounts will be credited in each sales year with 80 percent to OG&E s Oklahoma customers and the remaining 20 percent to OG&E. During 2005, OG&E recovered approximately $1.8 million in annual net profits from off-system sales. Including this amount, OG&E has recovered a total of $5.4 million related to the regulatory asset since December 31, 2002, which is in accordance with the 2002 Settlement Agreement. During 2005, OG&E also credited as required approximately $3.6 million in annual net profits from off-system sales to OG&E s Oklahoma customers and the net profits from off-system sales that exceeded the $5.4 million were shared with 80 percent to OG&E s Oklahoma customers and the remaining 20 percent to OG&E. Beginning January 1, 2006, the annual net profits from off-system sales were shared with 80 percent to OG&E s Oklahoma customers and 20 percent to OG&E.

OCC Order Confirming Savings

The 2002 Settlement Agreement required that, if OG&E did not acquire the New Generation by December 31, 2003, OG&E must credit $25.0 million annually (at a rate of 1/12 of $25.0 million per month for each month that the New Generation is not in place) to its Oklahoma customers beginning January 1, 2004 and continuing through December 31, 2006. As discussed in more detail below, in August 2003 OG&E signed an agreement to purchase a 77 percent interest in the McClain Plant, but due to a delay at the FERC, the acquisition was not completed by December 31, 2003. In the interim, OG&E entered into a power purchase agreement with the McClain Plant that delivered the savings guaranteed to OG&E s customers. OG&E requested that the OCC confirm that the steps it had taken, including the power purchase agreement, were satisfying the customer savings obligation under the 2002 Settlement Agreement and that OG&E would not be required to begin crediting its customers. On April 28, 2004, the OCC issued an order confirming that OG&E was delivering savings to its customers as required under the 2002 Settlement Agreement. The order removed any uncertainty over whether the OCC believed OG&E had to reduce its rates, effective January 1, 2004, while it awaited action by the FERC on its application to purchase the McClain Plant. A party to the OCC proceeding appealed the OCC s order to the Oklahoma Supreme Court. The appeal was denied and the OCC order is considered final. OG&E has filed reports with the OCC for the months of January 2004 through December 2006 supporting the savings from the McClain Plant. OG&E expects to file an application with the OCC in the second quarter of 2007 supporting its compliance with the 2002 Settlement Agreement. OG&E expects the OCC to issue an order by the end of 2007 in this matter.

Acquisition of McClain Power Plant

On July 9, 2004, OG&E completed the acquisition of a 77 percent interest in the McClain Plant. This transaction was intended to satisfy the requirement in the 2002 Settlement Agreement to acquire electric generation of not less than 400 MW s.

The closing of the purchase of the McClain Plant was subject to approval from the FERC. The FERC s July 2, 2004 approval was based on an offer of settlement in which OG&E agreed to undertake the following mitigation measures: (i) install certain transmission facilities designed to result in up to 600 MW s of available transfer capability (ATC) from the Redbud Energy LP (Redbud) facility to the OG&E control area; (ii) pending completion of these transmission upgrades, provide up to 600 MW s of ATC into OG&E s control area from the Redbud plant through changes to the dispatch of OG&E s generating units; and (iii) hire an independent market monitor to oversee OG&E s activity in its control area until the SPP implements a market monitor for the SPP regional transmission organization (RTO). OG&E completed the installation of the capital improvements and notified the FERC in writing on May 31, 2005 that these were completed. OG&E s obligation to redispatch its system to make 600 MW s of ATC available to the Redbud power plant terminated upon completion of the transmission upgrades. On June 20, 2006, the FERC issued an order that OG&E had fully satisfied all of the transmission upgrade requirements associated with the McClain Plant acquisition. Parties in this matter had 30 days to request a rehearing. No request for rehearing was filed with the FERC and OG&E believes the order is final. According to both OG&E s market monitoring plan and the applicable FERC orders, OG&E s market monitoring plan was set to terminate when the SPP installed its own market monitor. Given the implementation of the SPP s external market monitor effective December 1, 2006, OG&E s market monitoring plan effectively ended and OG&E s market monitor was dismissed on December 1, 2006. Also, on December 1, 2006, OG&E

notified the FERC that based on the status of the SPP s internal and external market monitors, the McClain settlement s market monitoring requirements had been fulfilled. On January 16,

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2007, OG&E s market monitor submitted its final report addressing the period from September 30, 2006 to November 30, 2006.

OG&E expects the addition of the McClain Plant, including the effects of an interim power purchase agreement OG&E had with NRG McClain LLC while OG&E was awaiting regulatory approval to complete the acquisition, will provide savings, over a three-year period (January 1, 2004 through December 31, 2006), in excess of $75.0 million to its Oklahoma customers. In the event OG&E is unable to demonstrate at least $75.0 million in savings to its customers during this 36-month period, OG&E will be required to credit its Oklahoma customers any unrealized savings below $75.0 million as determined subsequent to the end of the 36-month period. At this time, OG&E believes that it achieved at least $75.0 million in savings during this period. OG&E has filed reports with the OCC for the months of January 2004 through December 2006 supporting the savings from the McClain Plant. OG&E expects to file an application with the OCC in the second quarter of 2007 supporting its compliance with the 2002 Settlement Agreement. OG&E expects the OCC to issue an order by the end of 2007 in this matter.

OG&E Oklahoma Rate Case Filing

On May 20, 2005, OG&E filed with the OCC an application for an annual rate increase of approximately $89.1 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. The application also included, among other things, implementation of enhanced reliability programs in OG&E s system, increased fuel oil inventory, the establishment of a separate recovery mechanism for major storm expense, the establishment of new rate classes for public schools and related facilities, the establishment of a military base rider, the establishment of a new low income assistance tariff and the proposal to make the guaranteed flat bill pilot tariff permanent for residential and small business customers.

On September 12, 2005, several parties filed responsive testimony reflecting various positions on the issues related to this case. In particular, the testimony of the OCC Staff recommended that OG&E be entitled a rate increase of approximately $13.0 million, one-seventh the amount requested by OG&E in its May 20, 2005 application. The recommendations in the testimony of the Attorney General s office and the OIEC recommended a rate decrease of approximately $24 million and $31 million, respectively. Hearings in the rate case began on October 10, 2005 and concluded on October 24, 2005. On November 3, 2005, the Referee appointed by the OCC for this proceeding issued a report recommending an estimated rate increase of approximately $42 million for OG&E. On December 12, 2005, the OCC issued an order providing for a $42.3 million increase in rates and a 10.75 percent return on equity, based on a capital structure consisting of 55.7 percent equity and 44.3 percent debt. The new rates became effective in January 2006 pursuant to approved tariffs filed with the OCC. Also included in the order, among other things, are new depreciation rates effective January 2006 and a provision which modified OG&E s mechanism for the recovery of over or under recovered fuel costs from its customers to allow interest to be applied to the over or under recovery. See Note 1 for a discussion of amendments to the tariffs related to Fuel Clause Over Recoveries.

As part of the rate order issued by the OCC in December 2005, OG&E received OCC approval for the creation of two new rate classes, Public Schools-Demand and Public Schools Non-Demand. These two classes of service will provide OG&E flexibility to provide targeted programs for load management to public schools and their unique usage patterns. Another item approved in the order was the creation of service level fuel differentiation that allows customers to pay fuel costs that better reflect operational energy losses related to a specific service level. The OCC order also approved a military base rider which demonstrates Oklahoma s continued commitment to our military partners. OG&E s highly successful wind program was authorized to lower its cost on a per kwh basis, which provides subscribing customers the increased incentive to hedge against future natural gas prices. The order also enables OG&E s low-income qualified customers to receive relief on their summer electric bills by waiving the customer charge on their monthly bills from June to September of each year. Also included in OG&E s rate case application, but not approved, was the establishment of a separate recovery mechanism for major storm expense.

As provided in the 2002 Settlement Agreement, OG&E had the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the completion of the acquisition and operation of the McClain Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. OG&E completed its acquisition of the McClain Plant on July 9, 2004. Accordingly, OG&E ceased accruing various operating and related costs associated with the McClain Plant as a regulatory asset on July 8, 2005. At December 31, 2005, the actual incurred expenses included in the McClain Plant regulatory asset were approximately $24.9

million. Such costs will be recovered over a four-year time period as authorized in the OCC rate order beginning in January 2006. The OCC authorized approximately $15.5 million of the $24.9 million regulatory asset to be included in OG&E s rate base for purposes of earning a return.

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Enogex FERC Section 311 2001 Rate Case

Pursuant to a settlement accepted by the FERC in May 2003 to resolve Enogex s 2001 Section 311 rate case, Enogex assessed a fee under certain market conditions for processing customer gas gathered behind processing plants so that it met the heating value standards of natural gas transmission pipelines (default processing fee). Pursuant to Enogex s Statement of Operating Conditions (SOC) that was effective through September 30, 2004, if Enogex s annual processing gross margin exceeded a specified threshold, Enogex was required to record a default processing fee refund obligation in an amount equal to the lesser of the default processing fees or the amount of the processing margin in excess of the specified threshold. In June 2004, Enogex billed default processing fees of approximately $0.2 million, which was recorded as deferred revenue. Based on the processing gross margin for 2004, these default processing fees billed to customers were recorded as deferred revenue and were refunded or credited to customers by April 30, 2005.

Enogex FERC Section 311 2004 Rate Case and related FERC dockets and 2006 Fuel Filing

On September 1, 2004, Enogex made a filing at the FERC to revise its previously approved SOC to permit, among other things, the unbundling, effective October 1, 2004, of its previously bundled gathering and transportation services. As a result, effective October 1, 2004, the FERC regulates Enogex s Section 311 transportation but does not regulate Enogex s gathering. The OCC regulates gathering pursuant to Oklahoma statute.

On September 30, 2004, Enogex made its required triennial filing at the FERC to update its Section 311 maximum interruptible transportation rate. On September 29, 2004, Enogex filed an updated fuel factor with the FERC for the last quarter of 2004. Finally, on November 15, 2004, Enogex filed its annual updated system-wide fuel factor for fuel year 2005 (calendar year 2005). The proceedings were resolved by a unanimous settlement that the FERC approved without modification or condition, by order of September 19, 2005. The Settlement established new maximum interruptible Section 311 zonal rates for an East Zone and a West Zone on the Enogex system, confirmed that Enogex could unbundle its gathering and transportation services and permitted the fuel factor percentages for the last quarter of 2004 and for fuel year 2005 to become effective, as filed. The FERC order concluded all four proceedings which resulted in no refunds being due. Enogex must file its next rate case no later than October 1, 2007 to comply with the FERC s requirement for triennial filings.

Enogex 2007 Fuel Filing

As required by the fuel tracker provisions of its SOC, Enogex files annually to update its fuel percentages. On November 15, 2006, Enogex filed zonal fuel percentages for the 2007 calendar fuel year. As had been agreed in the settlement of the 2004 Section 311 rate case, Enogex established an East Zone fixed fuel percentage and a West Zone fixed fuel percentage to be recalculated annually to replace the system-wide fixed fuel percentage previously established annually for the Enogex system. By order dated December 19, 2006, the FERC approved and accepted Enogex s November 15, 2006 zonal fuel factors as fair and equitable effective January 1, 2007.

Gas Transportation and Storage Agreement

As part of the 2002 Settlement Agreement, OG&E also agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the 2002 Settlement Agreement. Because the required integrated service was not available in the marketplace from parties other than Enogex, OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of OG&E s natural gas-fired generation facilities. OG&E will pay Enogex annual demand fees of approximately $46.8 million for the right to transport specified maximum daily quantities (MDQ) and maximum hourly quantities (MHQ) of gas at various minimum gas delivery pressures depending on the operational needs of the individual generating facility. In addition, OG&E supplies system fuel in-kind for its pro-rata share of actual fuel and lost and unaccounted for gas on the transportation system. To the extent OG&E transports gas in quantities exceeding the prescribed MDQ s or MHQ s, it pays an overrun service charge. During the years ended December 31, 2006, 2005 and 2004, OG&E paid Enogex approximately $47.5 million, $47.6 million and $49.6 million, respectively, for gas transportation and storage services.

On July 14, 2005, the OCC issued an order in this case approving a $41.9 million annual recovery. The OCC order disallowed the recovery by OG&E of the amount that Enogex charges OG&E for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. Over the last three years, this amount has ranged from $1.0 million to $3.4 million annually. This amount was approximately $1.0 million in 2006 and is projected to be approximately $1.1 million in 2007. The OCC s order required OG&E to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC s order. Based on the order, OG&E s refund obligation was approximately $8.8 million. OG&E began refunding this obligation in September 2005 through its automatic fuel adjustment clause. The obligation was fully refunded at September 30, 2006.

In connection with the Enogex gas transportation and storage agreement, OG&E also recorded a refund obligation in Arkansas of approximately $1.1 million at December 31, 2005. OG&E provided to the APSC the OCC evidence and above findings showing that the Arkansas refund was calculated consistently with the Oklahoma refund. OG&E applied the refund obligation to its fuel clause under recoveries balance in April and customers began receiving this refund in April 2006 and will continue through March 2007.

Security Enhancements

On April 8, 2002, OG&E filed a joint application with the OCC Staff requesting approval for security investments and a rider to recover these costs from the ratepayers. On October 28, 2004, all parties signed a joint stipulation that contains the OCC Staff s recommendations and authorizes up to a $5 million annual recovery from OG&E s customers for security enhancement. On December 21, 2004, the OCC issued an order approving the stipulation which included a security rider. OG&E implemented the security rider with the first billing period in July 2006 and began charging OG&E s Oklahoma customers approximately $2.4 million annually. In compliance with the OCC order, in October 2006, OG&E filed a report regarding the recovery of the security costs through the authorized recovery rider for the period from July 1, 2006 to September 30, 2006. The OCC authorized tariff provides that the security rider may be updated quarterly. In December 2006, OG&E updated the security rider to recover approximately $2.9 million annually beginning with the first billing cycle in January 2007. OG&E also filed an application with the OCC on December 15, 2006 to amend its security plan to seek approval of approximately $7.6 million of cost increases related to the expanded scope of previously authorized projects and approximately $10.9 million for new security projects. The annual revenue requirement associated with the $18.5 million of capital expenditures is approximately $2.7 million. A procedural schedule was issued in February 2007 in this matter with hearings scheduled to begin on May 30, 2007. OG&E expects the OCC to issue an order in the third quarter of 2007 in this matter.

Competitive Bidding, Prudence Reviews and Other Rules for Electric Utility Providers

On March 10, 2005, the OCC filed Cause No. PUD 200500129 regarding Inquiry of the Oklahoma Corporation Commission into Guidelines for Establishing Rules for Competitive Bidding and Prudence Reviews for Electric Utility Providers. On June 10, 2005, the OCC voted to close this notice of inquiry and directed the OCC Staff to open a rulemaking to address the competitive bidding issue for electric utilities and other matters. Rules were adopted by the OCC on January 18, 2006 and became effective on April 3, 2006. The new rules: (i) establish a competitive procurement process for purchase of long-term electric generation and long-term fuel supplies; (ii) clarify existing law by requiring that a prudence review of utility fuel and generation procurement be conducted no less frequently than every two years; (iii) require a utility to submit an integrated resource plan to the OCC every three years; and (iv) establish a process in accordance with House Bill 1910 whereby a utility may seek pre-approval for recovery of costs associated with transmission upgrades, generation facility modifications caused by environmental requirements and the purchase or construction of generation facilities. OG&E does not expect these rules to have a significant impact on its operations.

OG&E SO2 Allowance Filing

On February 10, 2006, OG&E, the OCC Staff and AES Shady Point (AES) filed a joint application with the OCC to determine the treatment of proceeds received from OG&E s sale of SO2 allowances and how these proceeds will be shared between OG&E and its customers for any sales after December 31, 2005. In the application, the parties proposed that AES be held harmless from any reduction in OG&E s coal costs caused by the sale of SO2 allowances and that the proceeds of such sales be shared 80 percent with OG&E s Oklahoma customers and the remaining 20 percent to OG&E. A credit rider was requested to pass the proceeds from the sale of the SO2 allowances to Oklahoma customers. Any proceeds from the sale of SO2 allowances in the Arkansas and the FERC jurisdictions will flow through OG&E s automatic fuel adjustment clause. On June 5, 2006, the parties signed a settlement agreement providing that the proceeds of such sales after December 31, 2005 are to be shared 90 percent with OG&E s Oklahoma customers and the remaining 10 percent to OG&E. On June 26, 2006, the OCC approved the settlement agreement, including the 90/10 sharing mechanism. During 2006, OG&E recorded approximately $0.8 million in SO2 sales proceeds from sales in 2006 that are included as an increase in Operating Revenues in the Consolidated Statement of Income.

Review of OG&E s Fuel Adjustment Clause for Calendar Years 2003 and 2004

The OCC routinely audits activity in OG&E s fuel adjustment clause for each calendar year. On March 18, 2005, the OCC Staff filed Cause No. PUD 200500140 regarding Application of the Public Utility Division Director for Public Hearing to Review and Monitor OG&E s Fuel Adjustment Clause for Calendar Year 2003. On August 25, 2005, the OCC Staff filed Cause No. PUD 200500327 regarding Application of the Public Utility Division Director for Public Hearing to Review and Monitor OG&E s Fuel Adjustment Clause for Calendar Year 2004. On September 27, 2005, the OCC consolidated these two proceedings into one proceeding. Oklahoma Industrial Energy Consumers, AES, Redbud and PowerSmith Cogeneration Project, L.P intervened in this proceeding. On September 21, 2006, OG&E reached a settlement with the other parties in this case that required no refunds. On October 16, 2006, the OCC issued an order that approved the settlement concluding that OG&E s 2003 fuel costs were prudent and OG&E s 2004 fuel costs were appropriately calculated. Also, as part of the settlement, OG&E agreed to develop minimum filing requirements for future fuel adjustment clause reviews.

Cogeneration Credit Rider

On September 17, 2004, OG&E filed an application and testimony with the OCC requesting a cogeneration credit rider. The requested rider reduces cogeneration charges to customers because of decreasing cogeneration payments made by OG&E beginning January 2005. The cogeneration credit rider is necessary because amounts currently recovered from customers in base rates include historically higher cogeneration payments. OG&E s cogeneration credit rider has been updated and approved by the OCC in December of each year through December 2006 and any over/under recovery of the cogeneration credit rider in the current year and prior periods has been automatically included in the next year s rider. OG&E s current cogeneration credit rider expired December 31, 2006. The 2007 cogeneration credit rider is approximately $80.7 million and the total under recovery through 2006 was approximately $3.1 million. OG&E expects to file an application with the OCC in late 2007 to request a cogeneration credit for years after 2007.

Pending Regulatory Matters

OG&E Wind Power Filing

In January 2007, the Centennial wind farm in northwestern Oklahoma was fully in service. Through December 31, 2006, OG&E has spent approximately $171.1 million related to the Centennial wind farm. The OCC previously had approved a settlement agreement approving the Centennial wind power contract and a recovery rider for up to $205 million in construction costs and allowance for funds used during construction. The settlement also indicated that OG&E shall file for a general rate review during 2009 that will permit the OCC to issue an order no later than December 31, 2009 placing the Centennial wind farm in OG&E s rate base. On January 17, 2007, OG&E sent notice to the OCC to trigger the Centennial wind farm rider for the first billing cycle in February 2007. The recovery rider is designed to recover approximately $22.6 million in the first year of operations, which amount will decline over the life of the facility. Because the wind farm rider was implemented in February 2007, OG&E expects to recover approximately $20.7 million under the rider during the remaining 11 months of 2007. OG&E expects the recovery rider to remain in effect through late 2009. As explained below, the recent rate order from the APSC allows for the recovery of the portion of the Centennial wind farm allocable to OG&E s customers in Arkansas.

OG&E Arkansas Rate Case Filing

On July 28, 2006, OG&E filed with the APSC an application for an annual rate increase of approximately $13.5 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant, the Centennial wind power project and the costs of electric system expansion and upgrades based on a return on equity of 11.75 percent. On November 29, 2006, OG&E reached a settlement with the other parties in this case for an annual rate increase of approximately $5.4 million. In the settlement agreement, the parties also agreed that OG&E would be allowed to recover the full Arkansas portion of the Centennial wind farm. On January 5, 2007, the APSC approved the settlement and issued a rate order that provides for a $5.4 million annual increase in OG&E s electric rates and a 10.0 percent return on equity. The new Arkansas rates became effective in February 2007.

Proposed Construction of Power Plant

On July 18, 2006, the Company announced plans for OG&E to partner with American Electric Power s subsidiary, Public Service Company of Oklahoma (PSO), and the OMPA to build a new 950 MW coal unit at OG&E s existing Sooner plant location near Red Rock, Oklahoma. The estimated $1.8 billion project is the result of PSO s December 2005 request for proposals in which it sought bids for up to 600 MW s of new base load generation to be available to PSO. The unit, to be called Red Rock, is expected to be one of the cleanest of its size using coal from the Powder River Basin, which is located near Gillette, Wyoming. OG&E will operate the facility and expects to spend approximately $759 million in construction costs related to its 42 percent ownership percentage in the project and approximately $30 million in transmission costs for the project. PSO will own 50 percent and the OMPA will own eight percent. On December 1, 2006, OG&E submitted an application to the ODEQ for an air permit for the Red Rock plant. OG&E is seeking to have the air permit approved by the ODEQ by August 1, 2007. OG&E expects construction to begin in 2007 and is targeting the completion of the power plant in the 2011/2012 timeframe. OG&E filed an application with the OCC on January 17, 2007 asking the OCC to find that its portion of the construction costs are prudent and that a recovery mechanism should be established to recover OG&E s overall cost of capital on the investment during the construction period. The OCC rules provide that the OCC has up to 240 days to issue an order determining OG&E s pre-approval request, however OG&E s application requested that the OCC issue an order by July 20, 2007. The project is contingent upon numerous factors, including the successful completion of contract negotiations and the necessary regulatory and environmental approvals. Under the construction, ownership and operating agreement between OG&E, PSO and the OMPA, the parties could incur up to $60 million (of which approximately $25 million would be borne by OG&E) prior to the receipt of acceptable regulatory approvals and permits. If such approvals and permits were not obtained and the Red Rock project was abandoned, the Company can provide no assurance that these expenditures incurred by OG&E would be recoverable in future rates.

FERC Audit

On May 29, 2006, the FERC notified OG&E that it was commencing an audit to determine whether and how OG&E is complying with: (i) its Open Access Transmission Tariff; (ii) requirements of its market-based rate authorization; (iii) Standards of Conduct and Open Access Same-Time Information System; and (iv) wholesale fuel adjustment clause tariff and other requirements contained in the FERC regulations. Over the past several years, the FERC has conducted numerous audits of utilities across the country to ensure regulatory compliance. OG&E is currently in the process of providing information to the FERC. OG&E cannot predict either the final outcome or the timing of the completion of this audit.

Uniform Fuel Adjustment Clause Filing

On January 23, 2006, the Director of the Public Utility Division of the OCC filed Cause No. PUD 200600012 regarding an application to review the OCC s regulation of the automatic rate adjustment clauses of all public energy utilities operating in Oklahoma and subject to the OCC s jurisdiction. A technical conference for electric utilities was held on March 17, 2006. At this time, OG&E does not believe the outcome of this proceeding will significantly impact the Company.

Southwest Power Pool

OG&E is a member of the SPP, the regional reliability organization for all or parts of Oklahoma, Arkansas, Kansas, Louisiana, New Mexico, Mississippi, Missouri and Texas. OG&E participated with the SPP in the development of regional transmission tariffs and executed a Membership Agreement with the SPP to facilitate interstate transmission operations within this region in 1998. In October 2003, the SPP filed an application with the FERC seeking authority to form an RTO. In a FERC order dated October 1, 2004, the SPP was granted RTO status, subject to the SPP submitting a further compliance filing. On January 25, 2005, the FERC issued an order on compliance filing stating that the November 1, 2004 SPP compliance filing satisfied the October 1 FERC order. The approval of the SPP RTO application is not expected to significantly impact the Company s consolidated financial results.

The regional state committee, which is comprised of commissioners of the applicable state regulatory commissions, finished its process of formulating a methodology for funding transmission expansion in the SPP control area by allocating costs of transmission expansion to the SPP members who benefit. The SPP Board of Directors adopted this plan and filed it with the FERC on February 28, 2005, Docket No. ER05-652.

The FERC conditionally accepted the plan on April 21, 2005 with an effective date of May 5, 2005. The SPP made a second compliance filing on October 20, 2005 on various minor issues associated with the plan. On January 11, 2006, the FERC conditionally accepted the compliance filing, but required the SPP to make minor wording changes within 30 days. The SPP filed these minor wording changes on February 10, 2006.

The SPP filed on June 15, 2005, Docket No. ER05-1118, to create a real-time, offer-based energy imbalance service market that will require cash settlements for over or under generation. Market participants, including OG&E, will be required to submit resource plans and can submit offer curves for each resource available for dispatch. In addition, the SPP may order certain dispatching of generating units and has implemented a market monitoring plan that provides a clear set of rules, the potential consequences if the rules are violated and the areas in which an independent market monitor will examine and report. On March 20, 2006, the FERC issued an order that conditionally accepted a portion of the filing and suspended

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and rejected other portions of the filing. After several delays, the SPP Board of Directors voted to implement the energy imbalance service market no earlier than February 1, 2007. The SPP filed a certification of readiness to the FERC on January 18, 2007 that addressed issues raised by intervenors to the proceeding. The SPP energy imbalance service market began operations on February 1, 2007. As one condition to participation in the energy imbalance service market, OG&E, as well as other balancing authorities in the SPP, were required to submit open access tariff schedules setting forth the rates, terms and conditions for the provision of emergency energy service. OG&E submitted the required schedule on September 13, 2006, in Docket No. ER06-1488-000. On January 31, 2007, the FERC issued an order conditionally accepting OG&E s proposed emergency energy schedule, subject to OG&E submitting, within 30 days, a compliance filing making certain revisions required by the FERC.

On August 8, 2005, the SPP filed with the FERC for approval, Docket No. ER05-1285, tariff provisions which contained, among other items, a standard definition of transmission to be used in the SPP RTO. The definition provides a uniform basis for application of formula rates, exercise of functional control of the transmission system, planning and expansion of the transmission system, compensation of new transmission owners and provides for a three-year period for petitioning for deviations from the bright line definition. The basic definition of transmission facilities is similar to definitions accepted for other RTO s. On September 30, 2005, the FERC accepted the definition, with minor modification. On November 29, 2005, the SPP submitted a compliance filing consistent with the September 30 FERC directions for modification.

On August 5, 2004, OG&E filed with the APSC in Docket 04-111-U an application for approval of its participation in the SPP RTO. The application was filed pursuant to the provisions of the Arkansas code, which require that no public utility shall sell, lease, rent or otherwise transfer, in any manner, control of electric transmission facilities in this state without the approval of the APSC, provided that the approval is required only to the extent the transaction is not subject to the exclusive jurisdiction of the FERC or any other federal agency. On October 12, 2004, the SPP filed with the APSC in Docket 04-137-U an application for a Certificate of Public Convenience and Necessity for the limited purpose of managing and coordinating the use of certain transmission facilities located within the state of Arkansas. The APSC consolidated these two dockets, among others, and a public hearing was held on April 4, 2006. On August 10, 2006, the APSC issued an order granting OG&E, subject to certain conditions, permission to transfer functional control of its transmission facilities to the SPP. Also, in a separate order, the APSC granted the application of the SPP for a certificate of public convenience and necessity to transact business as a public utility in Arkansas due to asserting functional control of certain transmission facilities in Arkansas. The APSC, however, denied the SPP s request for a waiver of the applicability of various provisions of state law. Also, on December 1, 2006, the APSC issued an order closing the combined dockets described above.

Market-Based Rate Authority

On December 22, 2003, OG&E and OERI filed a triennial market power update based on the supply margin assessment test. On May 13, 2004, the FERC directed all utilities with pending three year market-based reviews to revise the generation market power portion of their three year review to address the new interim tests. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 that applied the interim tests to OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but did not pass the market share screen in the OG&E control area. OG&E and OERI provided an explanation as to why their failure of the market share screen in the OG&E control area should not be viewed as an indication that they can exercise generation market power.

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

On March 21, 2006, the FERC issued an order conditionally accepting OG&E s and OERI s proposal to mitigate the presumption of market power in the OG&E control area. First, the FERC accepted the additional information related to first-tier markets submitted by OG&E and OERI, and concluded that OG&E and OERI satisfy the FERC s generation market power standard for directly interconnected first-tier control areas. Second, the FERC directed the Company to make certain revisions to its mitigation proposal and file a cost-based rate tariff for short-term sales (one week or less) made within the OG&E control area. The FERC also expanded the scope of the proposed mitigation to all sales made within the OG&E control area (instead of only to sales sinking to load within the OG&E control area). On April 20, 2006, the Company submitted: (i) a compliance filing containing the specified revisions to the Company s market-based rate tariffs and the new cost-based rate tariff; and (ii) a request for rehearing asking the FERC to reconsider its expanded mitigation directive contained in the March 21, 2006 order. On May 22, 2006, the FERC issued a tolling order that effectively provided the FERC additional time to consider the April 20, 2006 rehearing request. On July 25, 2006 and August 25, 2006, pursuant to a FERC March 20, 2006 order, OG&E and OERI filed revisions to their market-based rate tariffs to allow them to sell energy imbalance service into the wholesale markets administered by the SPP at market-based rates. The FERC has not yet acted on OG&E s April 20, 2006, July 25, 2006 or August 25, 2006 filings. On February 6, 2007, OG&E and OERI submitted to the FERC a change in status report notifying the FERC that OG&E has placed into service OG&E s Centennial wind farm, a wind farm with a nameplate capacity rating of 120 MW. OG&E and OERI explained that adding this capacity was not material to the FERC s grant of market-based rate status to OG&E and OERI. The FERC has not yet acted on this change in status filing.

Department of Energy Blackout Report

On April 5, 2004, the U.S. Department of Energy issued its final report regarding the August 14, 2003 electric blackout in the eastern United States, which did not have an adverse affect on OG&E s electric system. The report recommends a number of specific changes to current statutes, rules or practices in order to improve the reliability of the infrastructure used to transmit electric power. The recommendations include the establishment of mandatory reliability standards and financial penalties for noncompliance. On April 14, 2004, the FERC issued a policy statement requiring electric utilities, including OG&E, to submit a report on vegetation management practices and indicating the FERC s intent to make North American Electric Reliability Council reliability standards mandatory. On June 17, 2004, OG&E filed its report on vegetation management practices with the FERC. During 2004, OG&E spent less than $0.2 million related to the implementation of blackout report recommendations. Implementation of the blackout report recommendations and the FERC policy statement could increase future transmission costs, but the extent of the increased costs is not known at this time.

National Energy Legislation

In late 2006, the FERC issued final regulations, pursuant to the 2005 Energy Policy Act, governing the elimination of mandatory purchase obligations by utilities from qualified facilities under PURPA. Those regulations offer the potential for OG&E as a member of the SPP to avoid new mandatory purchase obligations under certain conditions. In addition, in December 2006, Congress enacted and the President signed into law legislation extending through 2008 several energy tax credits, including the tax credit for renewable energy sources such as wind power, that otherwise would have expired in 2007. Looking ahead to 2007, Congress will likely consider several issues of interest to OG&E, including proposals to create a federal mandate for utilities to generate a specified percentage of their power from renewable sources, as well as proposals to impose mandatory global climate emission controls that might limit emissions of carbon dioxide and other so-called greenhouse gases from coal based electric generation facilities.

State Legislative Initiatives

Oklahoma

The 2006 legislative session concluded on May 26, 2006, with no legislation being passed that had a material impact on the Company. One bill, House Bill 1386 was introduced in the 2005 session and was carried over into the 2006 session. That bill, if passed, could have an impact on the

Company s ability to compete with other utility providers. The bill proposed that utilities be able to continue to serve and expand, if so desired, in service territories in which they currently serve but which a municipality annexes. OG&E believes current case law authorizes utilities to serve and expand in an area described above. House Bill 1386 would codify OG&E s belief. The bill failed to be heard in the Senate in 2006.

As discussed above, legislation was enacted in Oklahoma in the 1990 s that was to restructure the electric utility industry in that state. The implementation of the Oklahoma restructuring legislation was delayed and seems unlikely to proceed anytime in the near future. Yet, if ultimately enacted, this legislation could deregulate OG&E s electric generation assets and cause OG&E to discontinue the use of SFAS No. 71 with respect to its related regulatory balances. The previously-enacted Oklahoma legislation would not affect OG&E s electric transmission and distribution assets and OG&E believes that the continued use of SFAS No. 71 with respect to the related regulatory balances is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management believes that its regulatory assets, including those related to generation, are probable of future recovery.

Summary

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

19. Fair Value of Financial Instruments

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

December 31 *(In millions)*	**2006 Carrying Amount**	**Fair Value**	2005 Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 42.7**	**$ 42.7**	$ 125.4	$ 125.4
Interest Rate Swaps	**0.9**	**0.9**	0.1	0.1
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 10.3**	**$ 10.3**	$ 120.1	$ 120.1
Interest Rate Swaps	**---**	**---**	0.1	0.1
Long-Term Debt				
Senior Notes	**$ 807.2**	**$ 820.7**	$ 587.8	$ 612.2
Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
Enogex Notes continuing operations	**406.7**	**433.5**	407.6	441.2
Other	**---**	**---**	220.0	220.0

The carrying value of the financial instruments on the Consolidated Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company s interest rate swaps and energy trading contracts was determined primarily 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 and the potential impact of liquidating the position in an orderly manner over a reasonable period of time. The fair value of the Company s long-term debt is based on quoted market prices and management s estimate of current rates available for similar issues with similar maturities. See Note 7 for a discussion of Enogex s trading contracts with set off provisions.

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, 2006 and 2005, and the related consolidated statements of income, retained earnings, comprehensive income and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedule listed in the Index at Item 15. 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, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, 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 herein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of OGE Energy Corp. s internal control over financial reporting as of December 31, 2006, 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 14, 2007 expressed an unqualified opinion thereon.

As discussed in Notes 2, 3 and 15 to the consolidated financial statements, in 2006 the Company adopted Statement of Financial Accounting Standards No. 123 (Revised), Share-Based Payment, and Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma

February 14, 2007

Supplementary Data

Interim Consolidated Financial Information (Unaudited)

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

Quarter ended (*In millions, except per share data)*		Mar 31	Jun 30	Sep 30	Dec 31	Total
Operating revenues (A)(B)	**2006**	**$ 1,109.8**	**$ 934.3**	**$ 1,130.6**	**$ 830.9**	**$ 4,005.6**
	2005	1,265.3	1,330.2	1,674.1	1,641.9	5,911.5
Operating income (A)(B)	**2006**	**$ 51.8**	**$ 117.7**	**$ 220.6**	**$ 42.6**	**$ 432.7**
	2005	18.7	75.8	188.9	39.0	322.4
Net income (B)	**2006**	**$ 24.9**	**$ 93.7**	**$ 121.4**	**$ 22.1**	**$ 262.1**
	2005	5.3	38.5	111.1	56.1	211.0
Basic earnings per average common share (B)	**2006**	**$ 0.27**	**$ 1.03**	**$ 1.33**	**$ 0.25**	**$ 2.88**
	2005	0.06	0.43	1.23	0.62	2.34
Diluted earnings per average common share (B)	**2006**	**$ 0.27**	**$ 1.02**	**$ 1.31**	**$ 0.24**	**$ 2.84**
	2005	0.06	0.42	1.22	0.62	2.32

(A) These amounts have been restated due to the sales of EAPC and Enerven being reported as discontinued operations during 2005 and the sale of certain gas gathering assets in Kinta, Oklahoma, being reported as discontinued operations during 2006.

(B) As described above in Note 18 of the Notes to Consolidated Financial Statements, the OCC, in its order dated December 12, 2005, granted OG&E a $42.3 million annual increase in the rates charged by OG&E to its retail customers in Oklahoma. These increased rates became effective in January 2006 pursuant to approved tariffs filed with the OCC. In January 2007, OG&E determined that the approved tariffs had inadvertently authorized OG&E to collect, and OG&E had collected, approximately $26.7 million of additional fuel-related revenues during 2006 that was not intended by the December 12, 2005 order. As a result, OG&E filed with the OCC in January 2007 amendments to its previously-authorized tariffs, in order to cease recovery of the fuel-related revenues not intended by the December 12, 2005 order. The $26.7 million, plus $1.2 million of interest, was recorded as a liability under Fuel Clause Over Recoveries on the Consolidated Balance Sheet in the fourth quarter of 2006, and such amounts, along with other Fuel Clause Over Recoveries, will be credited to OG&E s Oklahoma customers in 2007 and 2008 through OG&E s automatic fuel adjustment clause. In addition, OG&E recorded a reduction in operating revenues of approximately $26.7 million and an increase in interest expense of approximately $0.5 million, which resulted in an after tax reduction in net income of approximately $16.7 million in the fourth quarter of 2006. On a quarterly basis, collections of such additional amounts under the previously-authorized tariffs represented approximately $7.8 million of operating revenues ($4.8 million of net income) for the quarter ended March 31, 2006, approximately $7.7 million of operating revenues ($4.7 million of net income) for the quarter ended June 30, 2006 and approximately $5.9 million of operating revenues ($3.6 million of net income) for the quarter ended September 30, 2006.

Dividends

COMMON STOCK

Common quarterly dividends paid (as declared) in 2006 were $0.33 ¼ each for the first three quarters of 2006 and was $0.34 for the fourth quarter of 2006. Common quarterly dividends paid (as declared) in 2005 and 2004 were $0.33 ¼.

Present rate $0.34

Payable 30th of January, April, July, and October

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

None.

Item 9A. Controls and Procedures.

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

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

Management s Report on Internal Control Over Financial Reporting

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

The Company s management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2006. 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, 2006, 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 management s assessment of the Company s internal control over financial reporting. This report appears on the following page.

/s/ Steven E. Moore
Steven E. Moore, Chairman of the Board
and Chief Executive Officer

/s/ Peter B. Delaney
Peter B. Delaney, President
and Chief Operating Officer

/s/ James R. Hatfield
James R. Hatfield, Senior Vice President
and Chief Financial Officer

/s/ Scott Forbes
Scott Forbes, Controller and
Chief Accounting Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC

ACCOUNTING FIRM

The Board of Directors and Stockholders

OGE Energy Corp.

We have audited management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that OGE Energy Corp. maintained effective internal control over financial reporting as of December 31, 2006, 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. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of 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, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, 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, management s assessment that OGE Energy Corp. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, OGE Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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, 2006 and 2005, and the related consolidated statements of income, retained earnings, comprehensive income and cash flows for each of the three years in the period ended December 31, 2006 of OGE Energy Corp. and our report dated February 14, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma

February 14, 2007

Item 9B. Other Information.

None.

PART III

Item 10. Directors and Executive Officers of the Registrant.

CODE OF ETHICS POLICY

The Company maintains a code of ethics for our chief executive officer and senior financial officers, including the chief financial officer and chief accounting officer, which is available for public viewing on the Company s web site address *www.oge.com* under the heading Investors , Corporate Governance. The code of ethics will be provided, free of charge, upon request. The Company intends to satisfy the disclosure requirements under Section 5, Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the code of ethics by posting such information on its web site at the location specified above. The Company will also include in its proxy statement the Audit Committee financial expert.

Item 11. Executive Compensation.

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

Equity Compensation Plan Information

The following table provides certain information as of December 31, 2006 with respect to the shares of the Company s Common Stock that may be issued under the existing equity compensation plans:

Plan Category	A Number of Securities to be Issued upon Exercise of Outstanding Options	B Weighted Average Price of Outstanding Options	C Number of Securities Remaining Available for future issuances under equity compensation plans (excluding securities reflected in Column A)
Equity Compensation Plans Approved by Shareowners (A)	1,485,602	$21.90	1,794,946 (B)

Equity Compensation Plans Not Approved by Shareowners	---	N/A	N/A

(A) Consists of the OGE Energy Corp. Stock Incentive Plan, which was approved by shareowners at the 1998 annual meeting and the OGE Energy Corp. 2003 Stock Incentive Plan, which was approved by shareowners at the 2003 annual meeting.
(B) Awards under the Stock Incentive Plan can take the form of stock options, stock appreciation rights, restricted stock or performance units.
N/A not applicable

Item 13. Certain Relationships and Related Transactions.

Item 14. Principal Accounting Fees and Services.

Items 10, 11, 12, 13 and 14 (other than Item 10 information regarding the Code of Ethics and Item 12 information required by Item 201 (d) of Regulation S-K) are omitted pursuant to General Instruction G of Form 10-K, since the Company will file copies of a definitive proxy statement with the SEC on or about March 31, 2007. Such proxy statement is incorporated herein by reference. In accordance with General Instruction G of Form 10-K, the information required by Item 10 relating to Executive Officers has been included in Part I, Item 4, of this Form 10-K.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) 1. Financial Statements

The following consolidated financial statements and supplementary data are included in Part II, Item 8 of this Report:

Consolidated Balance Sheets at December 31, 2006 and 2005

Consolidated Statements of Capitalization at December 31, 2006 and 2005

Consolidated Statements of Income for the years ended December 31, 2006, 2005 and 2004

Consolidated Statements of Retained Earnings for the years ended December 31, 2006, 2005 and 2004

Consolidated Statements of Comprehensive Income for the years ended December 31, 2006, 2005 and 2004

Consolidated Statements of Cash Flows for the years ended December 31, 2006, 2005 and 2004

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)

Supplementary Data

Interim Consolidated Financial Information

2. Financial Statement Schedule (included in Part IV)	**Page**
Schedule II - Valuation and Qualifying Accounts	134

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**
1.01	Underwriting Agreement, dated January 4, 2006 between OG&E and J.P. Morgan Securities Inc. and Wachovia Capital Markets, LLC, on behalf of themselves and the other underwriters named therein relating to $110,000,000 in aggregate principal amount of the Company s 5.15% Senior Notes, Series due January 15, 2016 and $110,000,000 in aggregate principal amount of its 5.75% Senior Notes, Series due January 15, 2036 (collectively, the Senior Notes (Filed as Exhibit 1.01 to OG&E s Form 8-K filed January 6, 2006 (File No. 1-1097) and incorporated by reference herein)
2.01	Purchase Agreement, dated as of May 14, 1999, by and between Tejas Gas, LLC and Enogex Inc. (Filed as Exhibit 2.01 to OGE Energy s Form 10-Q for the quarter ended June 30, 1999 (File No. 1-12579) and incorporated by reference herein)
2.02	Asset Purchase Agreement, dated as of August 18, 2003 by and between OG&E and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted

	exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy s Form 8-K filed August 20, 2003 (File No. 1-12579) and incorporated by reference herein)
2.03	Amendment No. 1 to Asset Purchase Agreement, dated as of October 22, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.04	Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.04 to OGE Energy s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.05	Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.05 to OGE Energy s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.06	Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.06 to OGE Energy s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.07	Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.07 to OGE Energy s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.08	Amendment No. 6 to Asset Purchase Agreement, dated as of March 12, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy s Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)
2.09	Amendment No. 7 to Asset Purchase Agreement, dated as of April 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy s Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)
2.10	Amendment No. 8 to Asset Purchase Agreement, dated as of May 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.11	Amendment No. 9 to Asset Purchase Agreement, dated as of June 2, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.12	Amendment No. 10 to Asset Purchase Agreement, dated as of June 17, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.13	Stock purchase agreement dated September 21, 2005 by and between Enogex Inc. and Atlas Pipeline Partners, L.P. (Filed as Exhibit 10.01 to OGE Energy s Form 8-K filed September 27, 2005 (File No. 1-12579) and incorporated by reference herein)

2.14	Asset purchase agreement dated March 30, 2006, by and between Enogex Gas Gathering, L.L.C. and Hiland Operating, Inc. (Filed as Exhibit 2.01 to the Company s Form 8-K filed April, 4, 2006 (File No. 1-12579) and incorporated by reference herein)
3.01	Copy of Restated Certificate of Incorporation. (Filed as Exhibit 3.01 to OGE Energy s Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)
3.02	Copy of Amended OGE Energy Corp. By-laws. (Filed as Exhibit 3.01 to OGE Energy s Form 8-K filed January 23, 2007 (File No. 1-12579) and incorporated by reference herein)
3.03	Copy of Amended OG&E By-laws. (Filed as Exhibit 3.02 to OGE Energy s Form 8-K filed January 23, 2007 (File No. 1-12579) and incorporated by reference herein)

4.01	Trust Indenture dated October 1, 1995, from OG&E to Boatmen s First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to Registration Statement No. 33-61821 and incorporated by reference herein)
4.02	Supplemental Trust Indenture No. 1 dated October 16, 1995, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E s Form 8-K filed October 24, 1995 (File No. 1-1097) and incorporated by reference herein)
4.03	Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E s Form 8-K filed July 17, 1997 (File No. 1-1097) and incorporated by reference herein)
4.04	Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E s Form 8-K filed April 16, 1998 (File No. 1-1097) and incorporated by reference herein)
4.05	Supplemental Indenture No. 4, dated as of October 15, 2000, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E s Form 8-K filed October 20, 2000 (File No. 1-1097) and incorporated by reference herein)
4.06	Supplemental Indenture No. 5 dated as of October 24, 2001, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.06 to Registration Statement No. 333-104615 and incorporated by reference herein)
4.07	Supplemental Indenture No. 6 dated as of August 1, 2004, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E s Form 8-K filed August 6, 2004 (File No 1-1097) and incorporated by reference herein)
4.08	Indenture dated as of November 1, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.01 to OGE Energy s Form 8-K filed November 12, 2004 (File No. 1-12579) and incorporated by reference herein)
4.09	Supplemental Indenture No. 1 dated as of November 9, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.02 to OGE Energy s Form 8-K filed November 12, 2004 (File No. 1-12579) and incorporated by reference herein)
4.10	Supplemental Indenture No. 7 dated as of January 1, 2006 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.08 to OG&E s Form 8-K filed January 6, 2006 (File No. 1-1097) and incorporated by reference herein)
10.01	Form of Change of Control Agreement for Officers of the Company and OG&E. (Filed as Exhibit 10.07 to OGE Energy s Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)
10.02	The Company s 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy s Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)
10.03	The Company s 2003 Stock Incentive Plan. (Filed as Annex A to OGE Energy s Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.04	OGE Energy Corp. Restoration of Retirement Income Plan, as amended by Amendments No. 1 and No. 2. (Filed as Exhibit 10.12 to OGE Energy s Form 10-K for the year ended December 31, 1996 (File No.1-12579) and incorporated by reference herein)
10.05	

	Amendment No. 3 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to OGE Energy s Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)
10.06	Amendment No. 4 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.14 to OGE Energy s Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

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10.07	OGE Energy Corp. Supplemental Executive Retirement Plan, as amended by Amendment No. 1. (Filed as Exhibit 10.07 to OGE Energy s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.08	The Company s 2003 Annual Incentive Compensation Plan. (Filed as Annex B to OGE Energy s Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.09	OGE Energy Corp. Deferred Compensation Plan and Amendment No. 1 to OGE Energy Corp. Deferred Compensation Plan. (Filed as Exhibit 10.12 to OGE Energy s Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)
10.10	Copy of Amended and Restated Rights Agreement, dated as of October 10, 2000 between OGE Energy Corp. and Chase Mellon Shareholder Services, LLC, as Rights Agent. (Filed as Exhibit 4.1 to OGE Energy s Form 8-K filed November 1, 2000 (File No. 1-12579) and incorporated by reference herein)
10.11	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 10-Q for the quarter ended September 30, 2002 (File No. 1-12579) and incorporated by reference herein)
10.12	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)
10.13	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)
10.14	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)
10.15	Amendment No. 1 to the Company s 2003 Stock Incentive Plan. (Filed as Exhibit 10.23 to OGE Energy s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.16	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)
10.17	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)
10.18	Amendment No. 5 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.26 to OGE Energy s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.19	Form of Non-Qualified Stock Option Agreement under 2003 Stock Incentive Plan. (Filed as Exhibit 10.29 to OGE Energy s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.20	Form of Performance Unit Agreement under 2003 Stock Incentive Plan. (Filed as Exhibit 10.30 to OGE Energy s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.21	Form of Restricted Stock Agreement under 2003 Stock Incentive Plan. (Filed as Exhibit 10.31 to OGE Energy s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.22	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)
10.23	Credit agreement dated December 6, 2006, by and between the Company, the Lenders thereto, Wachovia Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, and The Royal Bank of Scotland plc, UBS Securities LLC and Union Bank of California, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.01 to the Company s Form 8-K filed December 12, 2006 (File No. 1-12579) and incorporated by reference herein)
10.24	Credit agreement dated December 6, 2006, by and between OG&E, the Lenders thereto, Wachovia Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, and The Royal Bank of Scotland plc, Mizuho Corporate Bank and Union Bank of California, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.02 to the Company s Form 8-K filed December 12, 2006 (File No. 1-12579) and incorporated by reference herein)
10.25	Amendment No. 6 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.33 to OGE Energy s Form 10-K for the year ended December 31, 2005 (File No. 1-12579) and incorporated by reference herein)
10.26	Amendment No. 1 to the Company s 1998 Stock Incentive Plan.
10.27	Amendment No. 2 to the Company s 2003 Stock Incentive Plan.
10.28	Directors Compensation.
10.29	Executive Officer Compensation.
10.30	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.]
10.31	OGE Energy Corp. Employees Stock Ownership and Retirement Savings Plan, as amended and restated.
10.32	Construction, Ownership and Operating Agreement dated as of December 15, 2006, by and among OG&E, Oklahoma Municipal Power Authority and Public Service Company of Oklahoma. (Filed as Exhibit 99.01 to the Company s Form 8-K filed December 21, 2006 (File No. 1-12579) and incorporated by reference herein)
12.01	Calculation of Ratio of Earnings to Fixed Charges.
21.01	Subsidiaries of the Registrant.
23.01	Consent of Ernst & Young LLP.
24.01	Power of Attorney.
31.01	Certifications Pursuant to Rule 13a-15(e)/15d-15(e) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.01	Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Cautionary Statement for Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995.
99.02	Copy of OCC order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E s rate case. (Filed as Exhibit 99.02 to OGE Energy s Form 8-K filed December 16, 2005 (File No. 1-12579) and incorporated by reference herein)

Executive Compensation Plans and Arrangements

10.01	Form of Change of Control Agreement for Officers of the Company and OG&E. (Filed as Exhibit 10.07 to OGE Energy s Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)
10.02	The Company s 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy s Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)
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10.06	Amendment No. 4 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.14 to OGE Energy s Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)
10.07	OGE Energy Corp. Supplemental Executive Retirement Plan, as amended by Amendment No. 1. (Filed as Exhibit 10.07 to OGE Energy s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.08	The Company s 2003 Annual Incentive Compensation Plan. (Filed as Annex B to OGE Energy s Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.09	OGE Energy Corp. Deferred Compensation Plan and Amendment No. 1 to OGE Energy Corp. Deferred Compensation Plan. (Filed as Exhibit 10.12 to OGE Energy s Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)
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	Form of Restricted Stock Agreement under 2003 Stock Incentive Plan. (Filed as Exhibit 10.31 to OGE Energy s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.22	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)
10.25	Amendment No. 6 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.33 to OGE Energy s Form 10-K for the year ended December 31, 2005 (File No. 1-12579) and incorporated by reference herein)

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10.26	Amendment No. 1 to the Company s 1998 Stock Incentive Plan.
10.27	Amendment No. 2 to the Company s 2003 Stock Incentive Plan.
10.28	Directors Compensation.
10.29	Executive Officer Compensation.
10.31	OGE Energy Corp. Employees Stock Ownership and Retirement Savings Plan, as amended and restated.

OGE ENERGY CORP.

SCHEDULE II - Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Addition Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
		(In millions)			
Year Ended December 31, 2004					
Reserve for Uncollectible Accounts	$ 4.2	$ 5.8	$ ---	$ 5.5 (A)	$ 4.5
Year Ended December 31, 2005					
Reserve for Uncollectible Accounts	$ 4.5	$ 3.1	$ ---	$ 3.9 (A)	$ 3.7
Year Ended December 31, 2006					
Reserve for Uncollectible Accounts	$ 3.7	$ 7.0	$ ---	$ 6.3 (A)	$ 4.4

(A) Uncollectible accounts receivable written off, net of recoveries.

SIGNATURES

Pursuant to the requirements 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 16th day of February, 2007.

OGE ENERGY CORP.
(Registrant)

By /s/ Steven E. Moore
Steven E. Moore
Chairman of the Board and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this Report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/ s / Steven E. Moore		
Steven E. Moore	Principal Executive Officer and Director;	February 16, 2007
/ s / James R. Hatfield		
James R. Hatfield	Principal Financial Officer; and	February 16, 2007
/ s / Scott Forbes		
Scott Forbes	Principal Accounting Officer.	February 16, 2007
Herbert H. Champlin	Director;	
Luke R. Corbett	Director;	
Peter B. Delaney	Director;	
John D. Groendyke	Director;	

Robert Kelley	Director;
Linda P. Lambert	Director;
Robert Lorenz	Director;
Ronald H. White, M.D.	Director; and
J. D. Williams	Director.

/ s / Steven E. Moore

By Steven E. Moore (attorney-in-fact) February 16, 2007