OGE ENERGY CORP
Form DEF 14A
March 31, 2005

OGE Energy Corp. PO Box 321
Oklahoma City, Oklahoma 73101-0321
405-553-3000
www.oge.com

OG&E

March 31, 2005

Securities and Exchange Commission
Division of Corporation Finance
450 Fifth Street, N.W.
Washington, D.C. 20549

Gentlemen:

On behalf of OGE Energy Corp., enclosed for electronic filing, pursuant to Rule 14a-6(b), is a definitive copy of the proxy solicitation material relating to the Annual Meeting of Shareowners of the Company to be held on May 19, 2005.

Please note that copies of the proxy solicitation material are this day being sent to the New York and Pacific Stock Exchanges in accordance with Rule 14a-6(b).

The Company intends to commence mailing the foregoing material to its shareowners on approximately March 31, 2005, and to complete the same as soon as possible.

Sincerely,

/s/ Carla D. Brockman

Carla D. Brockman
Corporate Secretary

Enclosure

SCHEDULE 14A

SCHEDULE 14A INFORMATION

PROXY STATEMENT PURSUANT TO SECTION 14(A) OF THE SECURITIES
EXCHANGE ACT OF 1934 (AMENDMENT NO.)

Filed by the Registrant [X]

Filed by a Party other than the Registrant [ ]

Check the appropriate box:

[ ] Preliminary Proxy Statement

[ ] Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))

[X] Definitive Proxy Statement

[ ] Definitive Additional Materials

[ ] Soliciting Material Pursuant to Rule 14a-11(c) or Rule 14a-12

OGE ENERGY CORP.

(Name of Registrant as Specified In Its Charter)

(Name of Person(s) Filing Proxy Statement, if other than the Registrant)

Payment of Filing Fee (Check the appropriate box):

[X] No fee required

[ ] Fee Computed on table below per Exchange Act Rules 14a-6(i)(4) and 0-11.

1) Title of each class of securities to which transaction applies:

2) Aggregate number of securities to which transaction applies:

3) Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11 (Set forth the amount on which the filing fee is calculated and state how it was determined):

4) Proposed maximum aggregate value of transaction:

5) Total fee paid:

[ ] Fee paid previously with preliminary materials.

[ ] Check box if any part of the fee is offset as provided by Exchange Act Rule 0-11(a)(2) and identify the filing for which the offsetting fee was paid previously. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

1) Amount Previously Paid:

2) Form, Schedule or Registration Statement No.:

3) Filing Party:

4) Date Filed:

OGE Energy Corp.

Proxy Statement
and
Notice of Annual Meeting

May 19, 2005

OG+E

Contents

Notice of Annual Meeting
of Shareowners
and Proxy Statement

Thursday, May 19, 2005, at 10:00 a.m.

National Cowboy and Western Heritage Museum
1700 Northeast 63rd Street
Oklahoma City, Oklahoma

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OGE Energy Corp.

March 31, 2005

Dear Shareowner:

You are cordially invited to attend the annual meeting of OGE Energy Corp. at 10:00 a.m. on Thursday, May 19, 2005, at the National Cowboy and Western Heritage Museum, 1700 Northeast 63rd Street, Oklahoma City, Oklahoma.

The matters to be voted on at the meeting are described in the Notice of Annual Meeting of Shareowners and Proxy Statement on the following pages.

Even though you may own only a few shares, your proxy is important in making up the total number of shares necessary to hold the meeting. Whether or not you plan to attend the meeting, please vote your shares as soon as possible. A return envelope for your proxy card is enclosed for your convenience. Again this year, in addition to telephone voting, you also have the option of voting by the Internet. Instructions are included on the proxy card. Your vote will be appreciated.

Those arriving before the meeting will have the opportunity to visit informally with the management of your Company. In addition to the business portion of the meeting, there will be reports on our current operations and outlook.

Your continued interest in the Company is most encouraging and, on behalf of the Board of Directors and employees, I want to express our gratitude for your confidence and support.

Very truly yours,

/s/ Steven E. Moore

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

Notice of Annual Meeting of Shareowners

The Annual Meeting of Shareowners of OGE Energy Corp. will be held on Thursday, May 19, 2005, at 10:00 a.m. at the National Cowboy and Western Heritage Museum, 1700 Northeast 63rd Street, Oklahoma City, Oklahoma, for the following purposes:

(1) To elect three directors to serve for a three-year term;

(2) To ratify the appointment of Ernst & Young LLP as our principal independent accountants; and

(3) To transact such other business as may properly come before the meeting.

The map on page 27 will assist you in locating the National Cowboy and Western Heritage Museum.

Shareowners who owned stock on March 21, 2005, are entitled to notice of and to vote at this meeting or any adjournment of the meeting. A list of such shareowners will be available, as required by law, at our principal offices at 321 North Harvey, Oklahoma City, Oklahoma 73102.

/s/ Carla D. Brockman

Carla D. Brockman
Corporate Secretary

Dated: March 31, 2005

IMPORTANT YOUR PROXY CARD IS ENCLOSED IN THIS ENVELOPE

To assure your representation at the meeting, please vote your shares by the Internet, by telephone or by signing, dating and returning the proxy card promptly in the enclosed envelope. No postage is required for mailing in the United States. If your shares are held in the name of a broker, trust, bank or other nominee and you plan to attend the meeting and vote your shares in person, you should bring with you a proxy or letter from the broker, trustee, bank or other nominee confirming your beneficial ownership of the shares.

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Proxy Statement

March 31, 2005

Introduction

The Annual Meeting of Shareowners of OGE Energy Corp. (the Company) will be held at the National Cowboy and Western Heritage Museum, 1700 Northeast 63rd Street, Oklahoma City, Oklahoma, on May 19, 2005, at 10:00 a.m. For the convenience of those shareowners who may attend the meeting, a map is printed on page 27 that gives directions to the National Cowboy and Western Heritage Museum. At the meeting, it is intended that the first two items in the accompanying notice will be presented for action by the owners of the Company s Common Stock. The Board of Directors does not now know of any other matters to be presented at the meeting, but, if any other matters are properly presented to the meeting for action, the persons named in the accompanying proxy will vote upon them in accordance with their best judgment.

Your Board of Directors is sending you this proxy statement in connection with the solicitation of your proxy for use at the Annual Meeting. When you vote by Internet, by telephone or by mail, you appoint Steven E. Moore, William E. Durrett and Robert Kelley as your representatives at the Annual Meeting. Mr. Moore, Mr. Durrett and Mr. Kelley will vote your shares, as you have instructed them, at the Annual Meeting. This way, your shares will be voted whether or not you attend the Annual Meeting. Even if you plan to attend the meeting, it is a good idea to vote your shares in advance of the meeting, just in case your plans change.

If an issue comes up for vote at the meeting that is not on the proxy card, Mr. Moore, Mr. Durrett and Mr. Kelley will vote your shares, under your proxy, in accordance with their best judgment.

Voting Procedures; Revocation of Proxy

You may vote by mail, by telephone, by Internet, or in person. To vote by mail, simply complete and sign the proxy card and mail it in the enclosed, prepaid and preaddressed envelope. If you mark your voting instructions on the proxy card, your shares will be voted as you instruct. If you return a signed card but do not provide voting instructions, your shares will be voted **FOR** the three named nominees for director and **FOR** the ratification of Ernst & Young LLP as the Company s principal independent accountants.

Shareowners of record also may vote by the Internet or by using the toll-free number listed on the proxy card. Telephone and Internet voting also is available to shareowners who hold their shares in the Dividend Reinvestment and Stock Purchase Plan (DRIP) and the OGE Energy Corp. Employees Stock Ownership and Retirement Savings Plan (the Retirement Savings Plan). The telephone voting and Internet voting procedure is designed to verify shareowners through use of a number that is provided on each proxy card. This procedure allows you to vote your shares and to confirm that your instructions have been properly recorded. If you vote by telephone or by the Internet, you do not have to mail in your proxy card. Please see your proxy card for specific instructions.

If you wish to vote in person, we will pass out written ballots at the meeting. If you hold your shares in street name (*i.e.*, they are held by your broker in an account for you), you must request a legal proxy from your broker in order to vote at the meeting.

If you change your mind after voting your proxy, you can revoke your proxy and change your vote at any time before the polls close at the meeting. You can revoke your proxy by either signing another proxy with a later date, by voting by Internet, by telephone or by voting at the meeting. Alternatively, you may provide a written statement to the Company (attention Carla D. Brockman, Corporate Secretary) of your intention to revoke your proxy.

Record Date; Number of Votes

If you owned shares of our Common Stock at the close of business on March 21, 2005, you are entitled to one vote per share upon each matter presented at the meeting.

On March 1, 2005, there were 89,979,541 shares of Common Stock outstanding. The Company does not have any other outstanding class of voting stock. No person holds of record or, to our knowledge, beneficially owns more than 5% of our Common Stock.

Expenses of Proxy Solicitation

We will pay all costs associated with preparing, assembling and mailing the proxy cards and proxy statements. We also will reimburse brokers, nominees, fiduciaries and other custodians for their expenses in forwarding proxy materials to shareowners. Officers and

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other employees of the Company may solicit proxies by mail, personal interview, telephone, Internet and/or telegraph. In addition, we have retained Mellon Investor Services to assist in the solicitation of proxies, at a fee of approximately $7,500 plus associated costs and expenses. Our employees will not receive any additional compensation for soliciting proxies.

Mailing of Proxy Statement and Annual Report

This proxy statement and the enclosed proxy were mailed on or about March 31, 2005. Appendix A to this proxy statement includes our audited financial statements and management s discussion and analysis of financial condition and results of operations. This Appendix A, and our Summary Annual Report which contains Mr. Moore s letter to shareowners, condensed financial statements and a summary discussion of results of operations were mailed with this proxy statement on or about March 31, 2005, to all of our shareowners who owned stock on March 21, 2005.

Voting Under Plans

If you are a participant in our DRIP, your proxy will represent the shares held on your behalf under the DRIP and such shares will be voted in accordance with the instructions on your proxy. If you do not vote your proxy, your shares in the DRIP will not be voted.

If you are a participant in our Retirement Savings Plan, you will receive a voting directive for shares allocated to your account. The trustee will vote these shares as instructed by you in your voting directive. If you do not return your voting directive, the trustee will vote your allocated shares in the same proportion that all plan shares are voted.

Voting of Shares Held in Street Name by Your Broker

Brokerage firms have authority under New York Stock Exchange Rules to vote customers unvoted shares on certain routine matters, including the election of directors and ratification of the auditors. If you do not vote your proxy, your brokerage firm may either vote your shares on routine matters or leave your shares unvoted. We encourage you to provide instructions to your brokerage firm by voting your proxy. This ensures your shares will be voted at the meeting. When a brokerage firm votes its customers unvoted shares on routine matters, these shares are counted for purposes of establishing a quorum to conduct business at the meeting. A brokerage firm, however, cannot vote customers shares on non-routine matters. Accordingly, these shares (sometimes referred to as broker non-votes) are considered not entitled to vote on non-routine matters, rather than as a vote against the matter.

PROPOSAL NO. 1
ELECTION OF DIRECTORS

The Board of Directors of the Company presently consists of ten members. The directors are classified into three groups. One class of directors is elected at each year s Annual Meeting for a three-year term and to continue in office until their successors are elected and qualified. The following three persons are the nominees of the Board to be elected for such three-year term at the Annual Meeting to be held on May 19, 2005: Mr. Herbert H. Champlin, Mrs. Linda Petree Lambert and Dr. Ronald H. White, M.D. Each of these individuals is currently a director of the Company whose term as a director is scheduled to expire at the Annual Meeting.

Mrs. Martha W. Griffin will retire from the Board effective at the Annual Meeting. Mrs. Griffin has served as a director of the Company s principal subsidiary, Oklahoma Gas and Electric Company (OG&E), since 1987 and as a director of OGE Energy since its inception in 1996. The Board of Directors expresses its sincere appreciation and thanks to Mrs. Griffin for her many years of contribution and dedicated service.

The enclosed proxy, unless otherwise specified, will be voted in favor of the election as directors of the previously listed three nominees. The Board of Directors does not know of any nominee who will be unable to serve, but if any of them should be unable to serve, the proxy holder may vote for a substitute nominee. No nominee or director owns more than .96% of any class of voting securities of the Company.

For the nominees described herein to be elected as directors, they must receive the affirmative vote of the holders of a majority of the votes of shares of Common Stock present in person or by proxy and entitled to vote. Withholding authority is treated as a vote against.

Each director of the Company during 2004 was also a director of Oklahoma Gas and Electric Company (OG&E). The Company became the parent company of OG&E pursuant to a corporate reorganization, effective December 31,1996.

INFORMATION ABOUT DIRECTORS AND NOMINEES

The following contains certain information as of March 1, 2005, concerning the three nominees for directors, as well as the directors whose terms of office extend beyond the Annual Meeting on May 19, 2005.

Nominees for Election for Term Expiring at 2008 Annual Meeting of Shareowners

HERBERT H. CHAMPLIN, 67, is President of Champlin Explorations, Inc., an independent oil producer, and Chairman of Enid Data Systems, computer marketers, both located in Enid, Oklahoma. Mr. Champlin also was engaged separately during 2004 as a part of his principal business occupation in the petroleum industry and had interests in oil and gas wells. Mr. Champlin has been a director of the Company since December 31, 1996, and of OG&E since 1982, and is a member of the audit and compensation committees of the Board.

Photo

LINDA PETREE LAMBERT, 65, is President of Lasso Corporation, a diversified oil and gas investment company, president of Enertree, L.L.C., also an oil and gas investment company, and a partner in Petree Valley Farms, a working farm in Verden, Oklahoma. Ms. Lambert also serves as a member of the Board of Directors of InvesTrust, a privately held trust company, the Oklahoma National Memorial Foundation and the United Way of Oklahoma City. Ms. Lambert has been a director of the Company and of OG&E since November 2004, and is a member of the nominating and corporate governance committee of the Board.

Photo

RONALD H. WHITE, M.D., 68, is a practicing cardiologist and President, Partner and Director of Oklahoma Cardiovascular Associates, and a member of the Board of Managers of Oklahoma Heart Hospital. He was a member of the Board of Regents of the University of Oklahoma for 14 years. Presently Dr. White is a member of the Oklahoma State Regents for Higher Education. Dr. White has been a director of the Company since December 31, 1996, and of OG&E since 1989, and is a member of the compensation committee and the nominating and corporate governance committee of the Board.

Photo

Directors Whose Terms Expire at 2007 Annual Meeting of Shareowners

LUKE R. CORBETT, 58, is Chairman and Chief Executive Officer of Kerr-McGee Corporation, which is engaged in oil and gas exploration and production and chemical operations. He has been employed by Kerr-McGee

Corporation for more than 17 years, having served as Chairman and Chief Executive Officer since 1997; President and Chief Operating Officer from 1995 to 1997; and Group Vice President from 1992 to 1995. Mr. Corbett also serves as a member of the Board of Directors of Noble Corporation and of BOK Financial Corporation. Mr. Corbett will not be standing for reelection to the Board of BOK Financial Corporation and his term as a director of that corporation is expected to expire on April 26, 2005. Mr. Corbett has been a director of the Company since December 31, 1996, and of OG&E since December 1, 1996, and is chairman of the compensation committee and is a member of the audit committee of the Board.

Photo

ROBERT KELLEY, 59, is President of Kellco Investments Inc., a private investment company. Prior to May 1, 2001, he served as Chairman of the Board of Noble Affiliates, Inc., an independent energy company with exploration and production operations in the United States and international operations in China, Equador, Equatorial Guinea and the U.K. sector of the North Sea. Prior to October 2, 2000 he also served as President and Chief Executive Officer of Noble Affiliates, Inc. and of its three subsidiaries: Samedan Oil Corporation, Noble Gas Marketing, Inc. and Noble Trading, Inc. Mr. Kelley also serves as a member of the Board of Directors and audit committee of Lone Star Technologies, Inc., Cabot Oil and Gas Corporation and Seitel, Inc. The Board of Directors of the Company has determined that Mr. Kelley s service on these other audit committees does not impair his ability to effectively serve on the Company s audit committee. Mr. Kelley is a certified public accountant and his prior experiences include working for a public accounting firm and teaching accounting at two universities. Mr. Kelley has been a director of the Company since December 31, 1996, and of OG&E since January 17, 1996, and is chairman of the audit committee and is a member of the compensation committee of the Board.

Photo

J. D. WILLIAMS, 67, is founder and a former member of Williams & Jensen, P.C., a law firm in Washington, D. C., having resigned as a member of the firm in 1991. He remained an employee of the firm until his retirement in December 2004 and has agreed to make himself available as an independent contractor to provide limited services to the firm through December 31, 2007. During 2004, the Company paid Williams & Jensen less than $500,000 (which was less than 5% of the firm s annual revenues) for various legal services and expects to retain Williams & Jensen to provide similar services in 2005. Mr. Williams is involved in various civic and related matters and also serves as a member of the Board of Directors of Seitel, Inc. Mr. Williams has been a director of the Company and of OG&E since January 2001, and is chairman of the nominating and corporate governance committee of the Board.

Photo

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Directors Whose Terms Expire at 2006 Annual Meeting of Shareowners

WILLIAM E. DURRETT, 74, is Senior Chairman of the Board of American Fidelity Corporation, an insurance holding company and Chairman of North American Insurance Agency, Inc. From May 1998 to October 1999, he served as President and Chief Executive Officer of North American Insurance Agency, Inc. Mr. Durrett served as President and Chief Executive Officer of American Fidelity Corporation from 1978 to 1998 and as Chairman of American Fidelity Corporation from 1989 to 1998. He also serves as a member of the Boards and holds various executive positions in numerous other subsidiaries of American Fidelity Corporation. He serves as a director of BOK Financial Corporation and INTEGRIS Health. Mr. Durrett has been a director of the Company since December 31, 1996, and of OG&E since March 1991, and is a member of the audit committee and the nominating and corporate governance committee of the Board.

Photo

JOHN D. GROENDYKE, 60, is Chairman of the Board and Chief Executive Officer of Groendyke Transport Incorporated, a bulk truck transportation company in Enid, Oklahoma. Mr. Groendyke has worked at Groendyke Transport, Inc. since 1965. Mr. Groendyke is also Chairman of the Board and President of Bell Transport, Inc.; Oringderrf Tank Line, Inc.; Transport Company, Inc.; and Triple A Transport and is Chairman of the Board of GTI Insurance Co. Inc. and of James, Inc. Mr. Groendyke also serves as Director of Central Service

Photo

Corp. and Central National Bank. Mr. Groendyke has been a director of the Company and of OG&E since January 2003 and is a member of the compensation committee and the nominating and corporate governance committee of the Board.

STEVEN E. MOORE, 58, is Chairman, President and Chief Executive Officer of the Company and of OG&E, having been appointed to such positions with the Company effective December 31, 1996. Mr. Moore was appointed President of OG&E in August 1995, and as Chief Executive Officer and Chairman of OG&E in May 1996. Mr. Moore has been employed by OG&E for more than 30 years, having previously served as Senior Vice President of Law and Public Affairs. He also serves as a director of BOK Financial Corporation, INTEGRIS Health, and has served on many industry-wide committees in the electric utility industry. Mr. Moore has been a director of the Company since 1996 and of OG&E since October 1995.

Photo

The affirmative vote of the holders of a majority of the votes of shares of Common Stock present in person or by proxy and entitled to vote at the Annual Meeting will be required for the election of the three nominees as director. Withholding authority is treated as a vote against.

The Board of Directors recommends a vote FOR the election of the three nominees as director. Proxies solicited by the Board of Directors will be voted FOR the election of the three nominees as director, unless a different vote is specified.

INFORMATION CONCERNING THE BOARD OF DIRECTORS

Each member of our Board of Directors was also a director of OG&E during 2004. The Board of Directors of the Company met on six occasions during 2004 and the Board of Directors of OG&E met on six occasions during 2004. Each director attended at least 88% of the total number of meetings of the Boards of Directors and the committees of the Boards on which he or she served.

Committees. The standing committees of the Company s Board of Directors include a compensation committee, an audit committee and a nominating and corporate governance committee.

All members of these committees are independent, as independence is defined in the listing standards of the New York Stock Exchange. In addition, the Board has determined that Mr. Robert Kelley meets the Securities and Exchange Commission (SEC) definition of audit committee financial expert.

The members of the committees during 2004, the general functions of the committees and number of committee meetings in 2004 are set forth below.

Name of Committee and Members	General Functions of the Committee ***	Number of Meetings in 2004
Compensation Committee: Herbert H. Champlin Luke R. Corbett* Martha W. Griffin John D. Groendyke Robert Kelley Ronald H. White, M.D.	Oversees o compensation of directors and principal officers o executive compensation policy o benefit programs	5
Audit Committee: Herbert H. Champlin Luke R. Corbett William E. Durrett Robert Kelley* J.D. Williams**	Oversees financial reporting process o evaluate performance of independent auditors o select independent auditors o discuss with internal and independent auditors scope and plans for audits, adequacy and effectiveness of internal controls for financial reporting purposes, and results of their examinations o review interim financial statements and annual	6

	financial statements to be included in Form 10-K	
Nominating and Corporate Governance Committee: William E. Durrett Martha W. Griffin John D. Groendyke Linda Petree Lambert Ronald H. White, M.D. J.D. Williams*	Reviews and recommends o nominees for election as directors o membership of director committees o succession plans o various corporate governance issues	5

* Chairperson
** Mr. Williams ceased being a member of the Audit Committee on November 17, 2004.
*** The specific duties for each committee are set forth in the charter of the committee, which, in the case of the audit committee, is attached as Annex A, and, in the case of the compensation committee and the nominating and corporate governance committee, is available on the OGE Energy web site at *www.oge.com* under the heading Investors, Corporate Governance.

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Corporate Governance

The Board of Directors of the Company operates pursuant to a set of written Corporate Governance Guidelines that set forth the Company s corporate governance philosophy and the governance policies and practices that the Company has established to assist in governing the Company and its affiliates. The Guidelines state that the primary mission of the Board of Directors of the Company is to advance the interests of the Company s shareowners by creating a valuable long-term business.

The Guidelines describe Board membership criteria and the Board selection and member orientation process. The guidelines require that a majority of the directors must be independent and that members of each committee must be independent and state the Board s belief that the chief executive officer should be the only Company executive serving as a director. Absent approval of the Nominating and Corporate Governance Committee, no director may be nominated to a new term if he or she would be older than 70 at the time of election. The Guidelines also provide that no director may serve on more than three other boards of directors of publicly-held companies without the prior approval of the Nominating and Corporate Governance Committee. Directors whose professional responsibilities change, such as upon retirement or a change in employer, are required to submit a letter of resignation for the Board s consideration. The Guidelines provide that, except for employment arrangements with the chief executive officer, the Company will not engage in transactions with directors or their affiliates if such transactions would cast into doubt the independence of a director, present the appearance of a conflict of interest, or are otherwise prohibited by law, rule or regulation.

The Guidelines provide that the Compensation Committee of the Board will evaluate the performance of the chief executive officer on an annual basis and that the Nominating and Corporate Governance Committee will report to the Board at least annually on succession planning, which will include appropriate contingencies in the event the CEO retires or is incapacitated. The Guidelines also provide that the Nominating and Corporate Governance Committee is responsible for overseeing an annual assessment of the performance of the Board and Board committees, as well as for reviewing with the Board the results of these assessments. All of these tasks were completed in 2004.

The Guidelines provide that Board members have full access to officers and employees of the Company and, as necessary and appropriate, the Company s independent advisors, including legal counsel and independent accountants. The Guidelines further provide that the Board and each committee have the power to hire independent legal, financial or other advisors as they deem necessary. The Guidelines provide that the independent directors are to meet in executive session, generally coinciding with regularly scheduled Board meetings. In 2004, the independent directors met in executive session five times.

Our Code of Conduct, that is applicable to all of our directors, officers and employees, and the Corporate Governance Guidelines comply with the Sarbanes-Oxley Act of 2002 and the listing standards of the New York Stock Exchange. We also have a separate code of ethics that applies to our chief executive officer and our senior financial officers, including, our chief financial officer and our chief accounting officer, and that complies with the requirements imposed by the Sarbanes-Oxley Act of 2002 and the rules issued thereunder for codes of ethics applicable to such officers. The Board has reviewed and will continue to evaluate its role and responsibilities with respect to the new legislative and other governance requirements of the New York Stock Exchange. All of our corporate governance materials, including our codes of conduct and ethics, our Guidelines for Corporate Governance and all of our committee charters, are available for public viewing on the OGE Energy web site at *www.oge.com* under the heading Investors, Corporate Governance. Copies of our corporate governance material also are available without charge to shareowners who request them. Requests must be in writing and sent to: Corporate Secretary, OGE Energy Corp., 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321.

Director Independence. The Board of Directors of the Company is composed of ten directors, nine of whom are independent within the meaning of the New York Stock Exchange listing standards. Our Chairman and Chief Executive Officer is the only member of management serving as a director. For purposes of determining independence, we have adopted the following standards for director independence in compliance with the listing standards of the New York Stock Exchange:

o A director who is or was an employee, or whose immediate family member is or was an executive officer of the Company or any of our subsidiaries is not independent until three years after the end of such employment relationship;

o A director who received, or whose immediate family member received, more than $100,000 during any twelve-month period within the past three years in direct compensation from us or any of our subsidiaries, other than director and committee fees and pension or other forms or deferred compensation for prior service (provided such compensation is not contingent in any way on continued service), is not independent until three years after he or she ceases to receive more than $100,000 in any twelve-month period in such compensation;

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o A director who is a current partner or employee, or whose immediate family member is a current partner, of a firm that is the internal or external auditor of the Company or any of our subsidiaries is not independent;

o A director who was, or whose immediate family member was, within the last three years (but is no longer) a partner or employee of the internal or external auditor of the Company or any of our subsidiaries and who personally worked on the audit of the Company or any of its subsidiaries within that time is not independent;

o A director whose immediate family member is a current employee of the internal or external auditor of the Company or any of our subsidiaries and who participates in the firm s audit, assurance or tax compliance (but not tax planning) practice is not independent;

o A director who is or was employed, or whose immediate family member is or was employed, as an executive officer of another company where, at the same time, any of our or any of our subsidiaries present executives is or was serving on that company s compensation committee is not independent until three years after the end of such service or the employment relationship;

o A director who is a current employee, or whose immediate family member is a current executive officer, of a company that makes payments to, or receives payments from, us or any of our subsidiaries for property or services in an amount which, in any of the past three fiscal years, exceeds the greater of $1 million, or 2% of such other company s consolidated gross revenues, is not independent until three years after falling below such threshold; and

o No director qualifies as independent unless the Board affirmatively determines that the director has no other relationship with us or any of our subsidiaries (either directly or as a partner, shareholder or officer of an organization that has a relationship with us or any of our subsidiaries) that in the opinion of the Board of Directors could be considered to affect the directors ability to exercise his or her independent judgement as a director.

The Board determined that each of the following members of the Board, met the aforementioned independence standards: Herbert H. Champlin; Luke R. Corbett; William E. Durrett; Martha W. Griffin; John D. Groendyke; Robert Kelley; Linda Petree Lambert; Ronald H. White, M.D. and J.D. Williams. Mr. Moore does not meet the aforementioned independence standards, because he is the current Chief Executive Officer and an employee of the Company.

Standing Committees. Our Board has three standing committees audit; compensation; and nominating and corporate governance. All members of these committees are independent directors who are nominated and approved by the Board each year. The roles and responsibilities of these committees are defined in the committee charters adopted by the Board and provide for oversight of, among other things, executive management. The duties and responsibilities of the Board committees are reviewed regularly and are outlined above.

Lead Director. In an effort to strengthen independent oversight of management and to provide for more open communication, the Board has appointed Luke R. Corbett to serve in the role of lead director. The nonmanagement lead director chairs executive sessions of the Board conducted without management. These sessions will be held at least twice annually and were held five times in 2004.

Communications with the Board of Directors. Shareowners who wish to communicate with members of the Board, including the independent directors individually or as a group, may send correspondence to them in care of the Corporate Secretary at the Company s principal offices, 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. We currently do not intend to have the Corporate Secretary screen this correspondence, but we may change this policy if directed by the Board due to the nature and volume of the correspondence.

The Company encourages each of its Board members to attend the Annual Meeting and the directors are expected to attend whenever reasonably possible. All nine of the Board members serving at the time attended the Annual Meeting in 2004.

Prohibition on Loans. During 2004, the Company amended its Stock Incentive Plan to make it absolutely clear that all loans to executive officers are prohibited.

Auditors; Audit Partner Rotation. As described on page 12 below, the Company is requesting that the shareowners ratify the selection of Ernst & Young LLP as the Company s principal accountants for 2005. During 2004, the Audit Committee charter was amended to make it absolutely clear that the audit partners will be rotated as required by Sarbanes-Oxley.

Stock Ownership Guidelines. During 2004, the Company established stock ownership guidelines for its directors and officers. The terms of these guidelines are explained on page 17 in the Report of the Compensation Committee on Executive Compensation.

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Shareowner Nominations for Directors. It is expected that the nominating and corporate governance committee will consider nominees recommended by shareowners in accordance with our By-laws. Our By-laws provide that, if you intend to nominate director candidates for election at an Annual Meeting of Shareowners, you must deliver written notice to the Corporate Secretary not later than 90 days in advance of the meeting. The notice must set forth certain information concerning you and the nominee(s), including each nominee s name and address, a representation that you are entitled to vote at such meeting and intend to appear in person or by proxy at the meeting to nominate the person or persons specified in your notice, a description of all arrangements or understandings between you and each nominee and any other person pursuant to which the nomination or nominations are to be made by you, such other information as would be required to be included in a proxy statement soliciting proxies for the election of the nominee(s) and the consent of each nominee to serve as a director if so elected. The chairman of the Annual Meeting may refuse to acknowledge the nomination of any person not made in compliance with the foregoing procedure.

In considering individuals for nomination as directors, the nominating and corporate governance committee typically solicits recommendations from its current directors and is authorized to engage third party advisors, including search firms, to assist in the identification and evaluation of candidates. In 2004, the committee did not use any third party advisors to assist in the identification of potential candidates, but instead relied on an internal list compiled from recommendations of the committee and other members of the board.

The nominating and corporate governance committee has not established specific minimum qualities for director nominees or set forth specific qualities or skills that the nominating and corporate governance committee believes are necessary for one or more directors to possess. Instead, in evaluating potential candidates and incumbent directors for reelection, the nominating and corporate governance committee considers numerous factors, including judgment, skill, independence, integrity, experience with businesses and other organizations of comparable size, the interplay of the candidate s experience with the experience of other Board members, experience as an officer or director of another publicly-held corporation, understanding of management trends in general or in industries relevant to the Company, expertise in financial accounting and corporate finance, ability to bring diversity to the group, community or civic service, knowledge or expertise not currently on the Board, shareowner perception, and the extent to which the candidate would be a desirable addition to the Board and any committees of the Board. No particular weight is given to one factor over another on a general basis, but rather the factors are weighted in relationship to the perceived needs of the Board at the time of selecting nominees. The nominating and corporate governance committee will evaluate candidates recommended by shareowners on the same basis as they evaluate other candidates.

Following that process, in November 2004, the committee selected Ms. Linda Petree Lambert as the candidate that best suited our needs and recommended to the Board that she be elected as a director. Ms. Lambert s election was approved by the Board for a term expiring at this Annual Meeting.

Director Compensation. Compensation of non-officer directors of the Company during 2004 consisted of an annual retainer fee of $66,000, of which $2,000 was payable monthly in cash (the same amount that has been paid monthly since August 1994) and $42,000 was deposited in the director s account under the Directors Deferred Compensation Plan and converted to 1,624.758 common stock units based on the closing price of the Company s Common Stock on November 30, 2004. The chairmen of the audit, compensation and nominating and corporate governance committees received an additional $5,000 annual cash retainer in 2004. In addition, all non-officer directors received $1,000 for each Board meeting and $1,000 for each committee meeting attended. These amounts represent the total fees paid to directors in their capacities as directors of the Company and OG&E. For 2005, the fee for attendance at a Board or committee meeting was increased to $1,200. Also, the fee for acting as lead director was set at $10,000, the additional annual retainer for acting as chairman of the audit committee was increased to $10,000, and the additional annual retainer for acting as chairman of the compensation committee and the nominating and corporate governance committee remained at $5,000, with each of these additional amounts payable in November 2005.

Under the Directors Deferred Compensation Plan (the Plan), non-officer directors may defer payment of all or part of their attendance fees and the cash portion of their annual retainer fee, which deferred amounts are credited to their account on the date the deferred amounts otherwise would have been paid.

Amounts credited to the accounts are assumed to be invested in one or more of the investment options permitted under the Plan. During 2004, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company s Common Stock, a money market fund, a bond fund and several stock funds.

When an individual ceases to be a director of the Company, all amounts credited under the Plan are paid in cash in a lump sum or installments.

Historically, for those directors who retired from the Board of Directors after 10 years or more of service, the Company and OG&E continued to pay their annual cash retainer until their death. In November 1997, the Board eliminated this retirement policy for directors. Directors who retired prior to November 1997, however, will continue to receive benefits under the former policy.

PROPOSAL NO. 2 RATIFICATION OF THE APPOINTMENT OF ERNST & YOUNG LLP AS THE COMPANY S PRINCIPAL INDEPENDENT ACCOUNTANTS FOR 2005

The Audit Committee of the Board of Directors has selected Ernst & Young LLP as principal independent accountants to audit the accounts of the Company for the fiscal year ending December 31, 2005. Ernst & Young LLP was originally selected by the Board, upon the recommendation of the Audit Committee, as principal independent accountants for the Company effective May 16, 2002.

While the Audit Committee is responsible for the appointment, retention, termination and oversight of the Company s principal independent accountants, the Audit Committee and the Board are requesting, as a matter of policy, that shareowners ratify the appointment of Ernst & Young LLP as the Company s principal independent accountants. The Audit Committee is not required to take any action as a result of the outcome of the vote on this proposal. However, if the shareowners do not ratify appointment, the Audit Committee may investigate the reasons for the shareowners rejection and may consider whether to retain Ernst & Young or to appoint another auditor. Furthermore, even if the appointment is ratified, the Audit Committee in its discretion may direct the appointment of different principal independent accountants at any time during the year if it determines that such a change would be in the best interests of the Company and its shareowners.

Representatives of Ernst & Young LLP will be present at the Annual Meeting and will have an opportunity to make a statement if they so desire. Such representatives will be available to respond to appropriate questions from the shareowners at the Annual Meeting.

The affirmative vote of the holders of a majority of the votes of shares of Common Stock present in person or by proxy and entitled to vote at the Annual Meeting will be required for the ratification of the appointment of Ernst & Young LLP as the Company s principal independent accountants for 2005. Abstentions from voting in this matter are treated as votes AGAINST.

The Board of Directors recommends a vote FOR the ratification of the appointment of the Company s principal independent accountants. Proxies solicited by the Board of Directors will be voted FOR the ratification of the appointment of the Company s principal independent accountants, unless a different vote is specified.

REPORT OF AUDIT COMMITTEE

The audit committee of the Board of Directors of the Company (the Audit Committee) oversees the Company s financial reporting process on behalf of the Board of Directors. Management, however, has the primary responsibility for the financial statements and the reporting process including the systems of internal controls.

The Audit Committee has four members, none of whom has any relationship to the Company that interferes with the exercise of his or her independence from management and the Company, and each of whom qualifies as independent under the standards used by the New York Stock Exchange, where the Company s shares are listed. The Audit Committee operates under a written charter that has been approved by the Board of Directors. A copy of the Audit Committee charter is attached as Annex A. The Audit Committee annually reviews and reassesses the adequacy of its charter. Among other things, the charter specifies the policies for selecting the auditors (including rotation for the audit partner) and the scope of the Audit Committee s responsibilities and how it carries out those responsibilities, including structure, processes and membership requirements.

In fulfilling its oversight responsibilities regarding the 2004 financial statements, the Audit Committee reviewed with Company management the audited financial statements contained in our Annual Report. The Audit Committee s review included a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and the clarity of disclosures in the financial statements.

The Audit Committee also reviewed with the Company s independent auditors the Company s 2004 financial statements and management s assessment of the Company s internal controls over financial reporting. The Company s independent auditors are responsible for expressing an opinion on the conformity of our audited financial statements with accounting principles generally accepted in the United States and on management s assessment of the Company s internal controls over financial reporting. Our review with the independent auditors included a discussion of the auditors judgments as to the quality, not just the acceptability, of the Company s accounting principles and such other matters as are required to be discussed with the Audit Committee under Statement on Auditing Standards No. 61. In addition, the Audit Committee discussed with the independent auditors the auditors independence from management and the Company, including the matters in the written disclosures received by the Audit Committee pursuant to Rule 3600T of the Public Company Accounting Oversight Board.

The Audit Committee also discussed with the Company s internal and independent auditors the overall scope and plans for their respective audits for 2005. The Audit Committee meets with the internal and independent auditors, with and without management present, to discuss the results of their examinations, their evaluations of the Company s internal controls, and the overall quality of the Company s financial reporting. The Audit Committee held six meetings during 2004 and the Chairman of the Audit Committee met with the auditors by telephone on a quarterly basis to discuss the Company s quarterly financial statements.

Fees for Independent Auditors

Audit Fees

Total audit fees for 2004 were $1,942,965 for the Company s 2004 financial statement audit. These fees include $923,125 for the audit of internal control over financial reporting pursuant to the requirements of Sarbanes-Oxley section 404 and $66,614 for services in support of debt and stock offerings. Total audit fees for 2003 were $789,326, which includes $140,755 for services in support of debt and stock offerings.

The aggregate audit fees include fees billed for the audit of the Company s annual financial statements and for the reviews of the financial statements included in the Company s Quarterly Reports on Form 10-Q. For 2004, this amount includes estimated billings for the completion of the 2004 audit, which were rendered after year-end.

Audit-Related Fees

The aggregate fees billed for audit-related services for the fiscal year ended December 31, 2004 were $103,870, of which $61,500 was for employee benefit plan audits and $42,370 for other audit-related services.

The aggregate fees billed for audit-related services for the fiscal year ended December 31, 2003 were $91,550. These fees include $56,000 for employee benefit audits and $35,550 for other audit-related services.

Tax Fees

The aggregate fees billed for tax services for the fiscal year ended December 31, 2004 were $840,995. These fees include $176,207 for tax preparation and compliance ($74,882 for the review of federal and state tax returns and $101,325 for assistance with examinations and other return issues), $418,000 for tax assis-

tance with the Oklahoma Investment Tax Credits, meals and entertainment project, Oklahoma sales and use tax, $181,248 for a change in our tax accounting method and $65,540 for other tax services.

The aggregate fees billed for tax services for the fiscal year ended December 31, 2003 were $1,028,594. These fees include $174,338 for tax preparation and compliance ($53,490 for the review of federal and state tax returns and $120,848 for assistance with examinations and other return issues), $478,206 for a change in our tax accounting method, $338,742 for assistance with the Oklahoma Investment Tax Credits and $37,308 for other tax services.

All Other Fees

There were no other fees billed to the Company in 2004 or 2003 for other services.

The Audit Committee has considered whether the provision of non-audit services by the Company s principal independent public accountants is compatible with maintaining auditor independence.

In reliance on the review and discussions referred to above, the Audit Committee recommended to the Board of Directors, and the Board has approved, that the Company s audited financial statements be included in the Annual Report on Form 10-K for the fiscal year ended December 31, 2004, for filing with the Securities and Exchange Commission. The Audit Committee selected Ernst & Young LLP as the Company s independent public accountants for 2005. Representatives of Ernst & Young LLP will be present at the Annual Meeting of Shareowners and will have the opportunity to make a statement if they so desire. Such representatives will be available to respond to appropriate questions from shareowners at the meeting.

Audit Committee Pre-Approval Procedures

Rules adopted by the Securities and Exchange Commission in order to implement requirements of the Sarbanes-Oxley Act of 2002 require public company audit committees to pre-approve audit and non-audit services. Our Audit Committee follows procedures pursuant to which audit, audit-related and tax services, and all permissible non-audit services, are pre-approved by category of service. The fees are budgeted, and actual fees versus the budget are monitored throughout the year. During the year, circumstances may arise when it may become necessary to engage the independent public accountants for additional services not contemplated in the original pre-approval. In those instances, we will obtain the specific pre-approval of the Audit Committee before engaging the independent public accountants. The procedures require the Audit Committee to be informed of each service, and the procedures do not include any delegation of the Audit Committee s responsibilities to management. The Audit Committee may delegate pre-approval authority to one or more of its members. The member to whom such authority is delegated will report any pre-approval decisions to the Audit Committee at its next scheduled meeting.

For 2004, 100% of the audit-related fees, tax fees and all other fees were pre-approved by the Audit Committee or the Chairman of the Audit Committee pursuant to delegated authority.

Audit Committee
Robert Kelley, Chairman
Herbert H. Champlin, member
Luke R. Corbett, member
William E. Durrett, member
J.D. Williams*, member

* Mr. Williams served on the Audit Committee through November 17, 2004. He joins in the report of the Audit Committee to the extent it covers the period for which he served on the Committee during 2004.

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EXECUTIVE OFFICERS COMPENSATION

The Compensation Committee of the Board of Directors of the Company (the Committee) administers our executive compensation program. The Committee s report on compensation paid to executive officers during 2004 is set forth below.

REPORT OF COMPENSATION COMMITTEE ON EXECUTIVE COMPENSATION

General. The primary goals of the Committee in setting executive compensation in 2004 were: (i) to provide a competitive compensation package that would enable us to attract and retain key executives and (ii) to align the interests of our executives with those of our shareowners and also with our performance.

Compensation to our executive officers in 2004 was comprised primarily of salary, annual awards under our Annual Incentive Compensation Plan and long-term awards under our Stock Incentive Plan. In an effort to ensure the continued competitiveness of our executive compensation policies, the Committee engaged Towers Perrin, a nationally recognized compensation consulting firm, to help survey the marketplace. In setting base salaries and making annual and long-term incentive awards, the Committee considered the compensation paid at the 50th percentile to executives with similar duties within the following three groups: (i) the 2003 Energy Services Industry Executive Compensation Database (the Energy Services Survey Group), consisting of approximately 88 electric services organizations, (ii) the 2003 General Industry Executive Compensation Database (the General Industry Survey Group), consisting of more than 739 companies in general industries and (iii) the average of the Energy Services Survey Group and the General Industry Survey Group (the Blended Industry Survey Group).1 All compensation data from these surveys was size-adjusted so that it would compare to the Company s or a subsidiary s revenues, as appropriate, and was updated using a 3.75 percent update factor to reflect anticipated 2004 compensation levels.

The Committee s intent in setting salaries is to pay competitive rates. The annual and long-term incentive portions of an executive s compensation are intended to achieve the Committee s goal of aligning an executive s interests with our shareowners and with our performance. These portions of an executive s compensation are placed at risk and are linked to the accomplishment of specific results that are designed to benefit our shareowners and the Company, both in the long and short term. As a result, during years of excellent performance, executives are provided the opportunity to earn a highly competitive level of compensation and, conversely, in years of below-average performance, their compensation may be below competitive levels. Generally, higher level executive officers have a greater level of their compensation placed at risk.

A Federal tax law currently limits our ability to deduct an executive s compensation in excess of $1,000,000 unless such compensation qualifies as performance based compensation or certain other exceptions are met. The Committee has continued to analyze the structure of its salary and various compensation programs in light of this law. The Committee s present intent is to take appropriate steps to ensure the continued deductibility of its executive compensation. For this reason, the Committee and the Board of Directors recommended, and the shareowners approved, the Stock Incentive Plan and the Annual Incentive Plan at the 2003 Annual Meeting so that certain compensation payable thereunder would qualify for the performance based compensation exception to the $1,000,000 deduction limit and thereby continue to be deductible by the Company.

Base Salary. The base salaries for our executive officers in 2004 were designed to be competitive with the Blended Industry Survey Group for most of our executive officers and with the Energy Services Survey Group for those officers serving only at our utility subsidiary, OG&E. Base salaries of our executive officers generally approximated the salary at the 50th percentile of the range for executives with similar duties in the appropriate survey group. Actual base salaries were determined based on individual performance and experience. The salaries of executive officers for 2004 were determined in November 2003, with an effective date of January 1, 2004. Salaries were subject to adjustment during the year if an individual s duties and responsibilities changed. The 2004 base salary amounts for the most highly compensated executive officers are shown in the salary column of the Summary Compensation Table on page 19 and, for three of the six individuals listed, remained unchanged from their 2003 base salary amounts.

Annual Incentive Compensation Plan. Awards with respect to 2004 performance were made under the An-

1 The companies in the Energy Services Survey Group, General Industry Survey Group and Blended Industry Survey Group are not the same as the companies in the S&P 500 Electric Utilities Index utilized in the Stock Performance Graph on page 24. The survey groups were selected by Towers Perrin, the Committee s compensation consultants, and, in the judgment of the Committee, are appropriate peer groups to consider for compensation purposes.

nual Incentive Compensation Plan to 86 employees, including all executive officers. The Plan was designed to provide key management personnel with annual incentive awards, the payment of which is tied to the achievement of specified Company objectives. Payouts of the award were in cash and were dependent entirely on the achievement of the corporate goals that were established by the Committee in January 2004.

For Messrs. Moore, Strecker and Delaney, the three most senior executive officers of the Company at the time the corporate goals were established, the corporate goals were based: (i) 50% on a Company consolidated earnings per share target established by the Committee (the Earnings Target), (ii) 25% on a combined operating and maintenance expense and capital expenditure target for the Company and OG&E established by the Committee (the O&M/Capital Target), and (iii) 25% on consolidated net income of Enogex and its subsidiaries (the Unregulated Income Target). These three corporate goals were also used in establishing the corporate goals for all other executive officers. However, the weighting of the goals was slightly different for the remaining executive officers, with the corporate goals for one executive officer being based 50% on the Earnings Target and 50% on the O&M/Capital Target while for the remaining executive officers the corporate goals were based 50% on the Earnings Target, with the remaining 50% allocated between the O&M/Capital Target and the Unregulated Income Target based on the responsibilities of the individual s position.

The amount of the award for each executive officer was expressed as a percentage of base salary (the targeted amount), with the officer having the ability, depending upon achievement of the corporate goals, to receive from 0% to 150% of such targeted amount. For 2004, the targeted amount ranged from 25% to 75% of base salary and approximated the 50th percentile of the level of such awards granted to comparable executives in the Blended Industry Survey Group.

The percentage of the targeted amount that an officer ultimately received based on corporate performance was subject to being decreased, but not increased, at the discretion of the Committee. For 2004, corporate performance of the Earnings Target, the O&M/ Capital Target and the Unregulated Income Target exceeded the minimum levels of achievement established by the Committee and resulted in total payouts under the Annual Incentive Plan to executive officers ranging from 32.3% to 99.5% of their base salaries and from approximately 115.5% to 132.7% of their targeted amounts. Payouts under the Annual Incentive Plan are reflected in the bonus column of the Summary Compensation Table on page 19.

Long-Term Awards. Another significant component of executive compensation in 2004 was long-term awards under our Company s Stock Incentive Plan, which also was approved by the shareowners at the 2003 Annual Meeting. The Plan provides for the grant of any or all of the following types of awards: stock options, stock appreciation rights, restricted stock and performance units. In 2004, the Committee made awards of stock options and performance units. In making awards of stock options and performance units, the Committee considered numerous factors as discussed below and reviewed the expected value of long-term compensation payable to executives in the 50th percentile of the Energy Services Survey Group and the 50th percentile of the Blended Industry Survey Group. The expected value of long-term compensation payable to the most senior level executives in the 50th percentile of the Blended Industry Survey Group was substantially higher than the expected value of long-term compensation payable to comparable executives in the 50th percentile of the Energy Services Survey Group and substantially higher than the expected value of long-term compensation awarded by the Committee in the past to comparable executive officers at the Company. While the Committee intends to continue to consider the long-term compensation payable to comparable executives in the 50th percentile of the Blended Industry Survey Group in awarding long-term compensation to the Company s executive officers, the Committee s intent generally in 2004 was to provide executive officers with an aggregate value of long-term compensation equal to the expected value of long-term incentives payable to comparable executives in the 50th percentile of the Energy Services Survey Group.

Historically, the Committee had awarded long-term compensation in the forms of stock options and restricted stock. At its meeting in the fourth quarter of 2002, the Committee chose to discontinue awarding restricted stock and, instead, to make awards of stock options and performance units commencing in 2003, with 50% of an executive officer s award being in the form of stock options and 50% in the form of performance units. For 2004, the Committee chose to place less emphasis on stock options with 25% of an executive officer s award of long-term compensation being in the form of stock options and 75% in the form of performance units.

The stock options were granted to executive officers during the first quarter of 2004 at an exercise price equal to the fair market value at the date of the grant. The options have a ten-year term and vest over three years, with one-third of the options becoming exercisable at the end of each year. Since options were granted with an exercise price equal to the market value of our Common Stock at the time of grant, they provide no

value unless our stock price increases after the options are granted. These awards are thus tied to stock price appreciation in excess of the stock s value at time of grant, rewarding executives as if they shared in the ownership of the Company. The number of shares subject to options for each executive officer was determined by taking the expected value to be provided in options, as determined above, and dividing that amount by the estimated current value of an option for our stock using a variation of the Black-Scholes Option Pricing methodology provided by the Committee s outside compensation consultant. This resulted in executive officers receiving stock options with an estimated value of approximately 6.25% to 37.5% of their 2004 base salaries.

The performance units also were granted to executive officers during the first quarter of 2004. The number of performance units granted was determined by taking the amount of the executive s long-term award to be delivered in performance units (adjusted on a present value basis), as determined above, and dividing that amount by a recent closing price for the Company s Common Stock. This resulted in executives receiving performance units with an expected value at the date of grant of from 18.75% to 112.5% of their 2004 base salaries. The value of the performance units is substantially dependent upon the changing value of the Company s Common Stock in the marketplace. The terms of the performance units granted in 2004 were substantially the same as the terms of the performance units granted in 2003. Each executive officer is entitled to receive from 0% to 200% of the performance units contingently awarded to the executive based on the Company s total shareholder return over a three-year period (defined as share price increase plus dividends paid, divided by share price at beginning of the period) measured against the total shareholder return for such period (TSR) by a peer group selected by the Committee. The peer group for measuring the Company s TSR performance consists of approximately 80 utility holding companies and gas and electric utilities in the Standard & Poor s Utility Index.

CEO Compensation. The 2004 compensation for Mr. Moore consisted of the same components as the compensation for other executive officers. Mr. Moore s 2004 salary remained unchanged from the 2002 and 2003 amount of $710,000, and his 2004 targeted award under the

Annual Incentive Plan remained at 75% of this base salary, which the Compensation Committee believed were appropriate levels based on his performance and his prior experience. As a result of 2004 corporate performance of the corporate goals described above, he received a payout of $706,747 under the Annual Incentive Plan, representing approximately 99.5% of his base salary and 132.7% of his targeted award. The award of stock options and performance units made to Mr. Moore was based on his prior performance and a comparison of his award to the long-term compensation of other chief executive officers in the 50th percentile of the Energy Services Survey Group. Consideration also was given to Mr. Moore s prior experience with the Company and OG&E, his demonstrated leadership skills and his positive reputation within the community and utility industry. Based on these factors, the Committee determined to grant Mr. Moore stock options and performance units having an expected value of approximately 150% of his 2004 base salary, of which 25% was awarded in stock options and 75% in performance units.

Other Benefits. Virtually all of our employees, including executive officers, are eligible to participate in the Retirement Savings Plan and pension plan. Both the Retirement Savings Plan and pension plan have supplemental restoration plans that enable executive officers to receive the same benefits that they would have received in the absence of limitations imposed by the federal tax laws on contributions or payouts. In addition, a Supplemental Executive Retirement Plan (the SERP), which was adopted in 1993, offers attractive pension benefits to lateral hires. No officer, other than Mr. Delaney, participated in the SERP during 2004. The SERP is not expected to benefit other existing executive officers generally who remain employed by the Company or OG&E until age 65. In reviewing the benefits under the SERP, Retirement Savings Plan, pension plan and related restoration plans, the Committee sought in 2004 to provide participants with benefits at least commensurate with those offered by other utilities of comparable size. The restoration plans for the Retirement Savings Plan and pension plan contain provisions requiring their immediate funding in the event of certain mergers, consolidations or tender offers involving the Company.

Stock Ownership Guidelines. In an effort to further align management s interests with those of the shareowners, the Committee recommended, and the Board of Directors adopted, stock ownership guidelines for the officers of the Company and its subsidiaries during 2004. The Committee believes that linking a significant portion of an officer s current and potential future net worth to the Company s success, as reflected in the ownership of the Company s common stock and the price of the Company s common stock, helps to ensure that officers have a stake similar to that of the Company s shareowners. The share ownership guideline for each executive is based on the executive s position. The guideline for Chairman of the Board, President and Chief Executive Officer is five times base salary. The guidelines for other Company officers range from three and one-half to one and one-half times their base salaries. Each executive is expected to achieve the applicable ownership guideline within five years and the number of shares necessary to satisfy the guidelines is based on an assumed valuation of $25 per share. Similar guidelines were

adopted for members of the Board of Directors at a level of six times their annual retainer.

Conclusion. The Committee believes that our Company s executive compensation system serves the interests of the Company and our shareowners effectively. The Committee takes very seriously its responsibilities with respect to our executive compensation system. To this end, the Committee will continue to monitor and revise the compensation policies as necessary to ensure that our compensation system continues to meet the needs of the Company and our shareowners.

Compensation Committee
Luke R. Corbett, Chairman
Herbert H. Champlin, member
Martha W. Griffin, member
John D. Groendyke, member
Robert Kelley, member
Ronald H. White, M.D. member

SUMMARY COMPENSATION TABLE

The following table provides information regarding compensation paid or to be paid by us or any of our subsidiaries to the Chief Executive Officer and five other most highly compensated executive officers for the past three years. To the extent the table shows zeros for other annual compensation or payouts under long-term incentive plans for a particular year, no amounts were required to be reported in such year or, in the case of other annual compensation, the amounts were below the threshold required for disclosure under the SEC s rules.

	Long-Term Compensation	
Annual Compensation	Awards	Payouts

Name and Principal Position	Year	Salary ($)	Bonus(1) ($)	Other Annual Compensation(2) ($)	Restricted Stock Awards(3) ($)	Securities Underlying Options/ SAR (#)	LTIP Payouts ($)	All Other Compensation(4) ($)
S.E. Moore, Chairman,	2004	710,000	706,747	0	0	85,100	0	81,753
President and	2003	710,000	772,817	0	0	202,300	0	48,558
Chief Executive Officer	2002	710,000	149,885	0	0	218,500	0	35,361
A.M. Strecker	2004	191,667	165,350	0	0	40,500	0	34,690
Former Executive Vice	2003	460,000	433,939	0	0	90,400	0	37,174
President and Chief	2002	460,000	84,161	0	0	97,600	0	26,186
Operating Officer (5)								
P.B. Delaney (6)	2004	440,000	350,387	0	0	44,000	0	43,192
Executive Vice President	2003	400,000	348,312	0	0	98,200	0	16,705
and Chief Operating Officer	2002	300,000	24,192	0	0	84,900	0	156,577
J.R. Hatfield	2004	310,000	200,264	0	0	21,100	0	20,970
Sr. Vice President and	2003	310,000	221,932	0	0	51,800	0	28,151
Chief Financial Officer	2002	310,000	52,205	0	0	55,900	0	16,921
J.T. Coffman	2004	260,000	120,064	0	0	13,500	0	24,547
Sr. Vice President	2003	255,000	143,065	0	0	30,100	0	26,701
Power Supply	2002	255,000	8,883	0	0	32,500	0	20,036
S.R. Gerdes	2004	220,000	77,220	0	0	9,700	0	25,234
Vice President	2003	200,000	85,909	0	0	15,700	0	29,386
Utility Operations	2002	195,000	38,406	0	0	14,500	0	10,584

(1) As explained on page 15, amounts in this column reflect payouts under the Annual Incentive Compensation Plan.

(2) Each of the executive officers receives certain personal benefits, including reimbursement for tax and estate planning, and club memberships. The value of these personal benefits received by each of the Named Executive Officers is below the reporting threshold contained in the Securities and Exchange Commission s rules and, thus, is not included in this column.

(3) No shares of Restricted Stock were awarded in 2002, 2003 or 2004, however, shares of restricted stock had been awarded in prior years. In the absence of death, disability or normal retirement, the shares awarded to these individuals are subject to forfeiture for three years with the amount the recipient ultimately receives dependent on Company performance. The total number of shares and market value of Restricted Stock held by each of the named individuals as of December 31, 2004, were as follows: Mr. Moore, 12,889 shares, $341,687; Mr. Strecker, 5,759 shares, $152,671; Mr. Delaney, 0 shares, $0; Mr. Hatfield, 3,299 shares, $87,456; Mr. Coffman, 1,915 shares, $50,767; and Mr. Gerdes, 854 shares, $22,640. Dividends are paid to these individuals on the shares of Restricted Stock owned by them.

(4) Amounts in this column for 2004 reflect: (i) for Mr. Moore, $66,727 (Retirement Savings Plan and Deferred Compensation Plan) and $15,026 (insurance premiums); (ii) for Mr. Strecker, $28,152 (Retirement Savings Plan and Deferred Compensation Plan) and $6,538 (insurance premiums); (iii) for Mr. Delaney, $38,040 (Retirement Savings Plan and Deferred Compensation Plan) and $5,152 (insurance premiums); (iv) for Mr. Hatfield, $15,958 (Retirement Savings Plan and Deferred Compensation Plan) and $5,012 (insurance premiums); (v) for Mr. Coffman, $18,138 (Retirement Savings Plan and Deferred Compensation Plan) and $6,409 (insurance premiums); and (vi) for Mr. Gerdes, $13,766 (Retirement Savings Plan and Deferred Compensation Plan) and $11,468 (insurance premiums). A significant portion of the insurance premiums reported for each of these individuals is for life insurance policies and such premiums are recovered by the Company from the proceeds of the policies. Amounts shown as Retirement Savings Plan and Deferred Compensation Plan represent Company contributions for the individual under those plans.

(5) Mr. Strecker retired from the Company, effective June 1, 2004. See Employment Agreements and Change of Control Agreements for a summary of Mr. Strecker s consulting agreement with the Company after his retirement.

(6) Mr. Delaney joined the Company effective April 1, 2002.

OPTIONS AND STOCK APPRECIATION RIGHTS (SARs)

The following table indicates for each of the named executives (i) the extent to which the Company used stock options and SARs for executive compensation purposes in 2004 and (ii) the potential value of such options and SARs as determined pursuant to the SEC rules.

Options and SARs Granted in 2004

	Individual Grants				Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term	
(a)	(b)	(c)	(d)	(e)	(f)	(g)
Name	Options/SARs Granted #[(1)]	% of Total Options and SARs Granted to Employees in 2004	Exercise or Base Price ($/Share)	Expiration Date	5%($)[(2)]	10%($)[(2)]
S.E. Moore	85,100	22.37	$23.67	1/24/14	$1,274,878	$3,218,387
A.M. Strecker	40,500	10.65	23.67	1/24/14	606,728	1,531,665
P.B. Delaney	44,000	11.57	23.67	1/24/14	659,161	1,664,031
J.R. Hatfield	21,100	5.55	23.67	1/24/14	316,098	797,976
J.T. Coffman	13,500	3.55	23.67	1/24/14	202,243	510,555
S.R. Gerdes	9,700	2.55	23.67	1/24/14	145,315	366,843

(1) Options were granted on January 24, 2004 and become exercisable in one-third annual installments beginning one year from the date of grant. No SARs were awarded for 2004.

(2) The hypothetical potential appreciation shown in columns (f) and (g) for the named executives is required by the SEC rules. The amounts in these columns do not represent either the historical or anticipated future level of appreciation of our Common Stock.

The following table indicates for each of the named executives the number and value of exercisable and unexercisable options and SARs as of December 31, 2004.

Aggregated Option and SAR Exercises in 2004 and FY-End Option/SAR Value

(a)	(b)	(c)	(d)		(e)	
Name	Shares Acquired on Exercise (#)	Realized Value ($)	Number of Unexercised Options and SARs at 12/31/04 (#) - Exercisable (ex)/ Unexercisable (unex)		Value of Unexercised In-the-Money Options and SARs at 12/31/04 ($) - Exercisable (ex)/ Unexercisable (unex) *	
S.E. Moore	N/A	N/A	572,399	(ex)	$ 2,427,495	(ex)
			292,801	(unex)	$ 1,886,566	(unex)
A.M. Strecker	60,265	$524,731	296,135	(ex)	$ 1,037,769	(ex)
			0	(unex)	$ 0	(unex)
P.B. Delaney	10,000	$ 83,750	79,300	(ex)	$ 438,998	(ex)
			137,767	(unex)	$ 880,176	(unex)
J.R. Hatfield	35,166	$232,665	87,266	(ex)	$ 254,335	(ex)
			74,268	(unex)	$ 480,979	(unex)

J.T. Coffman	10,033	$ 74,395	68,566	(ex)	$	175,136	(ex)
			44,401	(unex)	$	283,150	(unex)
S.R. Gerdes	N/A	N/A	46,099	(ex)	$	196,514	(ex)
			25,001	(unex)	$	151,997	(unex)

* Share price on December 31, 2004 was $26.51. Options vest over three years with one-third becoming exercisable at the end of each year. Unexercisable options were granted on January 16, 2002 at a price of $22.23, January 27, 2003 at a price of $16.685, and January 24, 2004 at a price of $23.575. No SARs were granted in 2004.

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Long-Term Incentive Plans Awards In Last Fiscal Year

(a)	(b)	(c)	(d)	(e)	(f)
			Estimated future payouts under non-stock price-based plans		
Name	Number of shares, units or other rights (#)(1)	Performance or other period until maturation or payout(2)	Threshold (#)(2)	Target (#)(2)	Maximum (#)(2)
S.E. Moore	36,376	1/1/04-12/31/06	0	36,376	72,752
A.M. Strecker	2,400	1/1/04-12/31/06	0	2,400	4,800
P.B. Delaney	18,786	1/1/04-12/31/06	0	18,786	37,572
J.R. Hatfield	9,000	1/1/04-12/31/06	0	9,000	18,000
J.T. Coffman	5,772	1/1/04-12/31/06	0	5,772	11,544
S.R. Gerdes	4,132	1/1/04-12/31/06	0	4,132	8,264

(1) Represents awards of performance units made under the Stock Incentive Plan. Each performance unit represents the value of one share of our common stock.

(2) The number of performance units ultimately received at the end of the performance cycle is based on the Company s total shareholder return over a three-year period measured against the total shareholder return for such period by a peer group selected by the Committee. Following the end of the performance cycle, the performance units will be paid out two-thirds in shares of our common stock and one-third in cash.

PENSION PLAN TABLE

The Company and OG&E maintain a qualified non-contributory pension plan (the Retirement Plan) covering all employees who have completed one year of service. Subject to limitations imposed by the Employee Retirement Income Security Act of 1974 (ERISA), benefits payable under the Retirement Plan are based upon (i) the average of the five highest consecutive years of cash compensation (which for the executives named in the Summary Compensation Table consists of salary and bonus) during an employee s last ten years prior to retirement and (ii) length of service. Social Security benefits are deducted in determining benefits payable under the Retirement Plan. Compensation covered by the Retirement Plan includes salaries, bonuses and overtime pay. Benefits are reduced for each year prior to age 62 that an employee retires. For an employee retiring prior to age 62, there is an alternative method of computing the reduction in benefits that is based on years of service and age with an employee whose age and years of service total or exceed 80 at the time of retirement receiving no reduction in the benefits payable under the plan. An employee may elect at time of retirement to receive, in lieu of an annuity, a lump-sum payment equal to the present value of the annuity. Also, for employees hired after January 31, 2000, the pension plan is a cash balance plan, under which the Company annually will contribute to the employee s account an amount equal to 5% of the employee s annual compensation plus accrued interest. Employees hired prior to February 1, 2000 receive the greater of the cash balance formula or final average compensation formula. Retirement benefits are payable to participants upon normal retirement (at or after age 65) or early retirement (at or after attaining age 55 and completing five or more years of service), to former employees after reaching retirement age who have completed five or more years of service before terminating their employment and to participants after reaching retirement age upon total and permanent disability. As indicated above, the benefits payable under the Plan are subject to maximum limitations under ERISA. Should benefits for a participant at the time of retirement exceed the then permissible limits of ERISA, the Retirement Restoration Plan will provide benefits through a lump-sum distribution actuarially equivalent to the amounts that would have been payable to such participant annually under the Retirement Plan but for the ERISA limits. The Company and OG&E fund the estimated benefits payable under the Retirement Restoration Plan through contributions to a trust for the benefit of those employees who will be entitled to receive payments under the Retirement Restoration Plan.

The following table sets forth the estimated annual benefits payable upon normal retirement under the Retirement Plan and Retirement Restoration Plan to persons in the compensation classification specified.

Average Compensation 5 Highest Years	Years of Service at Retirement 10	15	20	25	30	35	40	45
$ 125,000	$ 16,501	$ 24,752	$ 33,002	$ 41,253	$ 49,504	$ 57,754	$ 66,005	$ 74,255
150,000	20,251	30,377	40,502	50,628	60,754	70,879	81,005	91,130
175,000	24,001	36,002	48,002	60,003	72,004	84,004	96,005	108,005
200,000	27,751	41,627	55,502	69,378	83,254	97,129	111,005	124,880
225,000	31,501	47,252	63,002	78,753	94,504	110,254	126,005	141,755
250,000	35,251	52,877	70,502	88,128	105,754	123,379	141,005	158,630
300,000	42,751	64,127	85,502	106,878	128,254	149,629	171,005	192,380
350,000	50,251	75,377	100,502	125,628	150,754	175,879	201,005	226,130
400,000	57,751	86,627	115,502	144,378	173,254	202,129	231,005	229,880
450,000	65,251	97,877	130,502	163,128	195,754	228,379	261,005	293,630
500,000	72,751	109,127	145,502	181,878	218,254	254,629	291,005	327,380
600,000	87,751	131,627	175,502	219,378	263,254	307,129	351,005	394,880
700,000	102,751	154,127	205,502	256,878	308,254	359,629	411,005	462,380
800,000	117,751	176,627	235,502	294,378	353,254	412,129	471,005	529,880
900,000	132,751	199,127	265,502	331,878	398,254	464,629	531,005	597,380
1,000,000	147,751	221,627	295,502	369,378	443,254	517,129	591,005	664,880
1,100,000	162,751	244,127	325,502	406,878	488,254	569,629	651,005	732,380
1,200,000	177,751	266,627	355,502	444,378	553,254	622,129	711,005	779,880
1,300,000	192,751	289,127	385,502	481,878	578,254	674,629	771,005	867,380
1,400,000	207,751	311,627	415,502	519,378	623,254	727,129	831,005	934,880
1,500,000	222,751	334,127	445,502	556,878	668,254	779,629	891,005	1,002,380
1,600,000	237,751	356,627	475,502	594,378	713,254	832,129	951,005	1,069,880
1,700,000	252,751	379,127	505,502	631,878	758,254	884,629	1,011,005	1,137,380
1,800,000	267,751	401,627	535,502	669,378	803,254	937,129	1,071,005	1,204,880
1,900,000	282,751	424,127	565,502	706,878	848,254	989,629	1,131,005	1,272,380

As of December 31, 2004, the credited years of service for the individuals listed in the Summary Compensation Table on page 19 are as follows: S. E. Moore 30 years; A. M. Strecker 33 years; P. B. Delaney 2 years; J. R. Hatfield 10 years; J. T. Coffman 34 years; and S. R. Gerdes 26 years.

In 1993, OG&E adopted a SERP which is an unfunded supplemental plan that is not subject to the benefits limit imposed by ERISA. The plan generally provides for an annual retirement benefit at age 65 equal to 65% of the participant s average cash compensation during his or her final 36 months of employment, reduced by Social Security benefits, by amounts payable under the Retirement and Restoration Plans described above and by amounts received under pension plans from other employers. For a participant in the SERP who retires before age 65, the 65% benefit is reduced, with the reduction being 1% per year for ages 62 through 64, an additional 2% per year for ages 60 through 61, an additional 4% per year for ages 58 through 59 and an additional 6% per year for ages 55 through 57, so that a participant retiring at age 55 would receive 32% of his average cash compensation during his final 36 months, reduced by the deductions set forth above. Other than Mr. Delaney, no employee participated in the SERP during 2004.

EMPLOYMENT AGREEMENTS AND CHANGE OF CONTROL ARRANGEMENTS

Effective April 1, 2002, Mr. Peter Delaney entered into a three-year employment agreement with the Company. The agreement expired by its terms on March 31, 2005. Under the terms of the agreement, Mr. Delaney was to serve as an Executive Vice President of the Company and as the Chief Executive Officer of the Company s unregulated businesses. Mr. Delaney was entitled to an annual base salary of not less than $400,000, an annual target award under the annual incentive plan of at least $240,000 (60% of his initial base salary) and an annual target award under the stock incentive plan of at least $400,000 (100% of his initial base salary). In addition, Mr. Delaney was entitled to (i) participate in all employee benefit plans and fringe benefits of the Company or an affiliate provided generally to executives of the Company, (ii) relocation expenses and (iii) participate in the Company s Supplemental Executive Retirement Plan (which is described on page 22).

Under the agreement, if Mr. Delaney s employment had terminated prior to March 31, 2005, he was entitled to various payments and benefits depending on whether his termination was due to death, disability, cause or some other reason. These provisions are no longer applicable, because, as noted above, the agreement expired by its terms on March 31, 2005, with Mr. Delaney continuing to serve as Executive Vice President and Chief Operating Officer of the Company.

Effective June 1, 2004, Mr. A.M. Strecker, former Executive Vice President and Chief Operating Officer, entered into a consulting agreement with the Company. The term of the agreement extends to May 31, 2005. Under the terms of the agreement, Mr. Strecker agreed to consult and advise the Company on specific matters designated by the chief executive officer and chief operating officer. In consideration for services provided under the agreement, Mr. Strecker was paid a lump sum retainer of $18,500 and $230 per hour, plus reasonable out-of-pocket expenses, for consulting services performed at the request of the chief executive officer or chief operating officer. The $230 per hour represented Mr. Strecker s annual salary at the time of his retirement ($460,000) divided by 2,000 hours. Mr. Strecker worked 201 hours in 2004 and the payment of $46,230 for such services at $230 per hour was deferred until the termination of his consulting agreement on May 31, 2005.

The Company and OG&E also have entered into employment agreements with each officer of the Company and OG&E. Under the agreements, the officer is to remain an employee for a three-year period following a change of control of the Company (the Employment Period). During the Employment Period, the officer is entitled to (i) an annual base salary in an amount at least equal to his or her base salary prior to the change of control, (ii) an annual bonus in an amount at least equal to his or her highest bonus in the three years prior to the change of control and (iii) continued participation in the incentive, savings retirement and welfare benefit plans. The officer also is entitled to payment of expenses and provision of fringe benefits to the extent paid or provided to (a) such officer prior to the change of control or (b) other peer executives of the Company. In addition, upon a change of control, Mr. Delaney will be considered vested under the Supplemental Executive Retirement Plan if he has not already attained age 55.

If, during the Employment Period, the officer s employment is terminated by the employer for reasons other than cause or disability or by such officer due to a change in employment responsibilities, the officer is entitled to the following payments: (i) all accrued and unpaid compensation and (ii) a severance payment equal to 2.99 times the sum of such officer s (a) annual base salary and (b) highest recent annual bonus. The officer also is entitled to continued welfare benefits for three years and outplacement services. If the payment of the foregoing benefits, when taken together with any other payments to the officer, would result in the imposition of the excise tax on excess parachute payments under Section 4999 of the Internal Revenue Code of 1986, as amended, then the severance benefits will be reduced if such reduction results in a greater after-tax payment to the officer. The officer is entitled to receive such amounts in a lump-sum payment within 30 days of termination. A change of control encompasses certain mergers and acquisitions, changes in Board membership and acquisition of securities of the Company.

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, 1999, and that all dividends were reinvested. As of March 1, 2005, the closing price of the Company s Common Stock on the New York Stock Exchange was $26.10.

[PERFORMANCE GRAPH OMITTED]

	1999	2000	2001	2002	2003	2004
OGE Energy Corp.	100	137	138	112	165	191
S&P 500 Index	100	91	80	62	80	89
S&P 500 Electric Utilities	100	154	128	109	135	171

SECURITY OWNERSHIP

The following table shows the number of shares of the Company s Common Stock beneficially owned on March 1, 2005, by each Director, by each of the Executive Officers named in the compensation table on page 19, and by all Executive Officers and Directors as a group:

	Number of Common Shares(1) (2) (3)		Number of Common Shares(1) (2) (3)
Herbert H. Champlin	50,583	S.E. Moore	860,913
Luke R. Corbett	32,147	A.M. Strecker	324,806
William E. Durrett	28,569	P.B. Delaney	168,481
Martha W. Griffin	28,572	J.R. Hatfield	148,663
John D. Groendyke	29,945	J.T. Coffman	118,478
Robert Kelley	42,859	S.R. Gerdes	69,023
Linda Petree Lambert	1,645	All Executive Officers and	
Ronald H. White, M.D.	38,794	Directors as a group	
J.D. Williams	23,849	(23 persons)	2,198,431

(1) Ownership by each executive officer is less than .96% of the class, by each director other than Mr. Moore is less than .06% of the class and, for all executive officers and directors as a group, is less than 2.44% of the class. Amounts shown include shares for which, in certain instances, an individual has disclaimed beneficial interest. Amounts shown for executive officers include 1,815,258 shares of Common Stock representing their interest in shares held under the Company s Retirement Savings Plan, Officer s Deferred Compensation Plan, and Stock Incentive Plan for which in certain instances they have voting power but not investment power.

(2) Amounts shown for Messrs. Champlin, Corbett, Durrett, Groendyke, Kelley, White and Williams and for Mrs. Griffin and Ms. Lambert include, 42,961; 26,705; 19,109; 4,445; 25,759; 31,694; 6,723; 17,812 and 1,645 common stock units, respectively, under the Directors Deferred Compensation Plan.

(3) Includes shares subject to stock options granted under the Company s Stock Incentive Plan, exercisable within 60 days following March 1, 2005, as follows: each non-officer director except Mr. Groendyke and Ms. Lambert, 5,100 shares; Mr. Groendyke and Ms. Lambert, 0 shares; Mr. Moore, 741,032 shares; Mr. Strecker, 296,135 shares; Mr. Delaney, 155,032 shares; Mr. Hatfield, 130,200 shares; Mr. Coffman, 93,933; and Mr. Gerdes, 59,399 shares.

The information on share ownership is based on information furnished to us by the individuals listed above and all shares listed are beneficially owned by the individuals or by members of their immediate family unless otherwise indicated. As explained in the Report of the Compensation Committee on page 17, the committee recommended and the Board of Directors adopted stock ownership guidelines in 2004 for directors and officers.

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EQUITY COMPENSATION PLAN INFORMATION

The following table provides certain information as of December 31, 2004 with respect to the shares of the Company s Common Stock that may be issued under the existing equity compensation plans:

	A	B	C
Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options	Weighted Average Price of Outstanding Options	Number of Securities Remaining Available for future issuances under equity compensation plans (excluding securities reflected in Column A)
Equity Compensation Plans Approved by Shareowners (1)	2,827,914	$22.16	2,209,763(2)
Equity Compensation Plans Not Approved by Shareowners	0	N/A	N/A

(1) 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.
(2) Awards under the Stock Incentive Plan can take the form of stock options, stock appreciation rights, restricted stock or performance units.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Under federal securities laws, our directors and executive officers are required to report, within specified dates, their initial ownership in the Company s Common Stock and subsequent acquisitions, dispositions or other transfers of interest in such securities. We are required to disclose whether we have knowledge that any person required to file such a report may have failed to do so in a timely manner. Except as described in the immediately succeeding two sentences, to our knowledge, all of our directors and officers subject to such reporting obligations have satisfied their reporting obligations in full for 2004. Messrs. Delaney, Hatfield, Coffman and Perkins each failed to timely file one report on Form 4 regarding the accrual of phantom stock units under the Company s deferred compensation plan. They each filed the required Form 4 approximately two weeks late.

SHAREOWNER PROPOSALS

Any shareowner proposal intended to be included in the proxy statement for the Annual Meeting in 2006 must be received by the Company on or before December 1, 2005. Proposals received by that date, deemed to be proper for consideration at the Annual Meeting and otherwise conforming to the rules of the SEC, will be included in the 2006 proxy statement.

If you intend to submit a shareowner proposal for consideration at the Annual Meeting, but do not want it included in the proxy statement, you must follow the procedures established by our By-laws. These procedures require that you notify us in writing of your proposal. Your notice must be received by the Corporate Secretary at least 90 days prior to the meeting and must contain the following information:

- a brief description of the business you desire to bring before the Annual Meeting and your reasons for conducting such business at the Annual Meeting,
- your name and address,
- the number of shares of Common Stock which you beneficially own, and
- any material interest you may have in the business being proposed.

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HOUSEHOLDING INFORMATION

We have adopted a procedure approved by the SEC called householding. Under this procedure, certain shareowners of record who have the same address and last name and do not participate in electronic delivery of proxy materials will receive only one copy of our Annual Report to Shareowners and proxy statement, unless one or more of these shareowners notifies us that they would like to continue to receive individual copies. This will reduce our printing costs and postage fees. Shareowners who participate in householding will continue to receive separate proxy cards. Also, householding will not in any way affect dividend check or dividend reinvestment statement mailings.

If you and other shareowners of record with whom you share an address currently receive multiple copies of our Summary Annual Report to Shareowners and/or proxy statement, or if you hold stock in more than one account, and in either case, you would like to receive only a single copy of the Annual Report to Shareowners or proxy statement for your household, please contact Mellon Investor Services; P.O. Box 3338, South Hackensack, NJ 07606 or phone toll free 1-888-216-8114.

If you participate in householding and would like to receive a separate copy of our Annual Report to Shareowners or this proxy statement, please call or write us at the following address or phone number: OGE Energy Corp. Shareowner Relations, 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321 or phone 405-553-3211. We will deliver the requested documents to you promptly upon receipt of your request.

Some banks, brokers and other nominee record holders may be participating in the practice of householding proxy statements and annual reports. This means that only one copy of our proxy statement or Annual Report to Shareowners may have been sent to multiple shareowners in your household. We will promptly deliver a separate copy of either document to you if you call or write us at the following address or phone number: OGE Energy Corp. Shareowner Relations, 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321 or phone 405-553-3211. If you want to receive separate copies of the Annual Report to Shareowners and proxy statement in the future, or if you are receiving multiple copies and would like to receive only one copy for your household, you should contact your bank, broker, or other nominee record holder.

LOCATION OF THE NATIONAL COWBOY AND WESTERN HERITAGE MUSEUM

East Bound or West Bound I-44

Exit to Martin Luther King Ave., continuing north approximately .2 miles. Proceed west on Northeast 63rd Street .5 miles to National Cowboy and Western Heritage Museum.

MAP

Annex A

OGE ENERGY CORP.

AUDIT COMMITTEE CHARTER

Purposes

The purposes of the Audit Committee of the Board of Directors of OGE Energy Corp. (the Company) are to assist the Board of Directors in monitoring: (i) the integrity of the Company s financial statements, (ii) the Company s compliance with legal and regulatory requirements, (iii) the independent auditors qualifications and independence, and (iv) the performance of the independent auditors and the Company s internal audit function. The Committee also shall prepare the Committee s report, made pursuant to the Securities Exchange Act of 1934 (the Exchange Act), to be included in the Company s annual proxy statement (the Audit Committee Report).

Composition

Size. The size of the Committee shall be determined by the Board of Directors, but it always must have at least three members.

Qualifications. Each Committee member shall have all of the following qualifications:

1) Each Committee member shall meet the independence criteria of (a) the rules of the New York Stock Exchange, Inc. (NYSE), as such requirements are interpreted by the Board of Directors in its business judgment, and (b) Section 301 of the Sarbanes-Oxley Act of 2002 and the rules and listing requirements promulgated thereunder by the Securities and Exchange Commission (SEC), including Rule 10A-3 under the Exchange Act, and the NYSE.

2) Each Committee member shall be financially literate or shall become financially literate within a reasonable period of time after his or her appointment to the Committee. Additionally, at least one member of the Committee shall have accounting or related financial management expertise sufficient to meet the criteria of a financial expert within the meaning of Section 407 of the Sarbanes- Oxley Act of 2002 and any rules promulgated thereunder by the SEC. The Board of Directors shall determine, in its business judgment, whether a member is financially literate and whether at least one member has the requisite accounting or financial management expertise and meets the financial expert criteria of Section 407 of the Sarbanes-Oxley Act of 2002 and any rules promulgated thereunder by the SEC. The designation or identification of a person as an audit committee financial expert shall not (a) impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Audit Committee and Board of Directors in the absence of such

designation or identification, or (b) affect the duties, obligations or liability of any other member of the Audit Committee or Board of Directors.

3) Each Committee member shall receive as compensation from the Company only those forms of compensation as are not prohibited by Section 301 of the Sarbanes-Oxley Act of 2002 and the rules and listing requirements promulgated thereunder by the SEC and the NYSE. Permitted compensation includes (a) director s fees (which includes all forms of compensation paid to directors of the Company for service as a director or member of a Board Committee) and/or (b) fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Company provided that such compensation is not contingent in any way on continued service. Additional directors fees may be paid to Audit Committee members to compensate them for the significant time and effort they expend in performing their duties as Audit Committee members.

4) If a Committee member simultaneously serves on the audit committee of more than three public companies (including the Company), the Board of Directors must determine that such simultaneous service would not impair the ability of such member to effectively serve on the Committee. The Company shall disclose any such determination in its annual proxy statement.

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Selection. The Board of Directors will appoint the members and the Chair of the Committee. Each Committee member will serve at the pleasure of the Board and for such term as the Board may decide or until such Committee member is no longer a Board member. Committee members may be replaced by the Board at any time.

Duties and Responsibilities

The Committee is responsible for overseeing the Company s financial reporting process on behalf of the Board of Directors and preparing the Audit Committee Report. While the Audit Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Committee to plan or conduct audits or to determine that the Company s financial statements and disclosures are complete and accurate and are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the independent auditors.

The Committee is directly responsible for the appointment, termination, compensation, retention, evaluation and oversight of the work of the Company s independent auditors (including resolution of disagreements between management and the auditors regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Company.

In performing its responsibilities, the Committee shall:

1) Retain the Independent Auditors: The Committee has the sole authority to (a) directly appoint, retain, compensate, evaluate and terminate the Company s independent auditors, (b) approve all audit services (including the fees and terms thereof), and (c) approve any permitted non-audit services (including the fees and terms thereof). The Committee is to exercise this authority in a manner consistent with Sections 201, 202 and 301 of the Sarbanes-Oxley Act of 2002 and the rules and listing standards promulgated thereunder by the SEC and NYSE. The Committee may form and delegate authority to subcommittees consisting of one or more members when appropriate, including the authority to grant any pre-approvals of all audit and permitted nonaudit services, provided that decisions of such subcommittee to grant pre-approvals shall be presented to the Committee at its next scheduled meeting. Prior to retaining the independent auditors, the Committee shall evaluate the auditors qualifications, performance and independence, which evaluation shall include, among other things, a review of the auditors prior work for the Company, consideration of the opinions of management and the internal auditors, and a review of the reports and other information described in paragraphs (2) and (3) below. The Committee shall report its conclusions with respect to the independent auditors to the Board.

2) Review and Discuss the Auditors Quality Control: The Committee is to, at least annually, obtain and review a report by the independent auditors describing (a) the audit firm s internal quality control procedures, (b) any material issues raised by the most recent internal quality control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and (c) any steps taken to deal with any such issues.

3) Review and Discuss the Independence of the Auditors: In connection with the retention of the Company s independent auditors, the Committee is to, at least annually, review and discuss the information and reports provided by management or the auditors relating to the independence of the audit firm, including, among other things, information related to the non-audit services

provided and expected to be provided by the auditors and other relationships between the independent auditors and the Company. The Committee is responsible for (a) ensuring that the independent auditors submit at least annually to the Committee a formal written statement delineating all relationships between the auditors and the Company consistent with applicable independence standards, (b) engaging in a dialogue with the auditors with respect to any disclosed relationship or services that may impact the objectivity and independence of the auditors, and (c) taking appropriate action in response to the auditors report to satisfy itself of the auditors independence. In connection with the Committee s evaluation of the independent auditors, the Committee shall review and evaluate the lead partner of the independent auditors and shall cause the regular rotation, to the extent required by Section 10(A)(j) of the Exchange Act, of the audit partners who

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serve on the Company s audit engagement team. The Committee also will consider whether, in order to assure continuing auditors independence, it is appropriate to adopt a policy of rotating the independent auditing firm on a regular basis.

4) Set Hiring Policies: The Committee is to set hiring policies for employees or former employees of the independent auditors, which include the restrictions set forth in Section 206 of the Sarbanes- Oxley Act of 2002 and any rules promulgated thereunder by the SEC.

5) Review and Discuss the Audit Plan: The Committee is to review and discuss with the independent auditors the plans for, and the scope of, the annual audit and other examinations, including the adequacy of staffing and compensation.

6) Review and Discuss Conduct of the Audit: The Committee is to review and discuss with the independent auditors the matters required to be discussed by Statement on Auditing Standards No. 61 relating to the conduct of the audit, as well as any audit problems or difficulties the auditor encountered in the course of the audit work and management s response, including (a) any restriction on audit scope or the auditors activities or on access to requested information, (b) any disagreements with management, (c) significant issues discussed with the independent auditors national office and (d) whether the auditors have any reason to believe there has been conduct in violation of Rule 13b2-2 under the Exchange Act. The Committee is to decide all unresolved disagreements between management and the independent auditors regarding financial reporting.

7) Review and Discuss Financial Statements and Disclosures: The Committee is to review and discuss with appropriate officers of the Company and the independent auditors the annual audited and quarterly financial statements of the Company, including reviewing (a) the Company s specific disclosures under Management s Discussion and Analysis of Financial Condition and Results of Operations, and (b) the disclosures regarding internal controls and other matters required by Section 302 and 404 of the Sarbanes-Oxley Act of 2002 and any rules promulgated thereunder by the SEC. The Committee shall recommend to the Board whether the audited financial statements of the Company should be included in the Company s Form 10-K.

8) Review and Discuss Earnings Press Releases: The Committee is to review and discuss earnings and other financial press releases (including any use of pro forma or adjusted non-GAAP information), as well as financial information and earnings guidance provided to analysts and rating agencies (which review may occur after issuance and may be done generally as a review of the types of information to be disclosed and the form of presentation to be made).

9) Review and Discuss Internal Audit Plans and Senior Internal Auditing Executive: The Committee is to review and discuss with the senior internal auditing executive and appropriate members of the staff of the internal auditing department the plans for and the scope of their ongoing audit activities, including adequacy of staffing and compensation. The Committee also is to review the appointment and replacement of the senior internal auditing executive.

10) Review and Discuss Internal Audit Reports: The Committee is to review and discuss with the senior internal auditing executive and appropriate members of the staff of the internal auditing department the annual report of the audit activities, examinations and results thereof of the internal auditing department.

11) Review and Discuss the Systems of Internal Accounting Controls: The Committee is to review and discuss with the independent auditors, the senior internal auditing executive, the General Counsel and, if and to the extent deemed appropriate by the Chair of the Committee, members of their respective staffs the adequacy of the Company s internal accounting controls, the Company s financial, auditing and accounting organizations and personnel, and the Company s policies and compliance procedures with respect to business practices, which shall include (a) by Sections 302 and 404 of the Sarbanes-Oxley Act of 2002 and any rules promulgated thereunder by the SEC, and (b) a review with the independent auditors of their attestation of management s

assessment of internal controls over financing reporting and the independent auditors analysis of the adequacy of disclosures about changes in internal control over financial reporting.

12) Review and Discuss the Recommendations of Independent Auditors: The Committee is to review and discuss with the senior internal auditing executive and the appropriate members of the staff of the internal auditing department recommendations made by the independent auditors and the senior internal auditing executive, as well as such other matters, if any, as such persons or other officers of the Company may desire to bring to the attention of the Committee.

13) Review and Discuss the Audit Results: The Committee is to review and discuss with the independent auditors (A) the report of their annual audit, or proposed report of their annual audit, (B) the accompanying management letter, if any, (C) the reports of their reviews of the Company s interim financial statements conducted in accordance with Statement on Auditing Standards No. 71, and (D) the reports of the results of such other examinations outside of the course of the independent auditors normal audit procedures that the independent auditors may from time to time undertake. The foregoing shall include the reports required by Section 204 of the Sarbanes- Oxley Act of 2002 and any rules promulgated thereunder by the SEC and, as appropriate, a review of (a) major issues regarding (i) accounting principles and financial statement presentations, including any significant changes in the Company s selection or application of accounting principles and (ii) the adequacy of the Company s internal controls and any special audit steps adopted in light of material control deficiencies, (b) analyses prepared by management and/or the independent auditors setting forth significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including analyses of the effects of alternative GAAP methods on the financial statements, and (c) the effect of regulatory and accounting initiatives, as well as off-balance sheet structures, on the financial statements of the Company.

14) Obtain Assurances under Section 10A(b) of the Exchange Act: The Committee is to obtain assurance from the independent auditors that in the course of conducting the audit, there have been no acts detected or that have otherwise come to the attention of the audit firm that require disclosure to the Committee under Section 10A(b) of the Exchange Act.

15) Discuss Risk Management Policies: The Committee is to discuss with management the Company s major financial risk exposures and the steps management has taken to monitor and control the exposures, including the Company s risk assessment and risk management policies and guidelines.

16) Obtain Reports Regarding Conformity With Legal Requirements and the Company s Code of Business Conduct and Ethics: The Committee is to periodically obtain reports from management, the Company s senior internal auditing executive and the independent auditor that the Company and its affiliated entities are in conformity with applicable legal requirements and the Company s Code of Ethics (including the Code of Ethics for CEO and Senior Financial Officers). The Committee is to review and discuss reports of insider and affiliated party transactions. The Committee should advise the Board with respect to the Company s policies and procedures regarding compliance with applicable laws and regulations and with the Company s Code of Ethics (including the Code of Ethics for CEO and Senior Financial Officers).

17) Establish Procedures for Complaints Regarding Financial Statements or Accounting Policies: The Committee is to establish procedures for (A) the receipt, retention, and treatment of complaints received by the Company from employees regarding accounting, internal accounting controls, or auditing matters; and (B) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters as required by Section 301 of the Sarbanes-Oxley Act of 2002 and the rules and listing requirements promulgated thereunder by the SEC and the NYSE. The Committee is to discuss with management and the independent auditors any correspondence with regulators or governmental agencies and any complaints or concerns regarding the Company s financial statements or accounting policies.

18) Discuss With General Counsel Matters Regarding Financial Statements or Compliance Policies: The Committee should discuss with the Company s General Counsel legal matters that may have a material impact on the financial statements or the Company s compliance policies.

19) Review and Discuss Other Matters: The Committee should review and discuss such other matters that relate to the accounting, auditing and financial reporting practices and procedures of the Company as the Committee may, in its own discretion, deem desirable in connection with the review functions described above.

20) Make Board Reports: The Committee should report its activities regularly to the Board of Directors in such manner and at such times as the Committee and the Board of Directors deem appropriate, but in no event less than once a year. Such report should include the Committee s conclusions with respect to its assessment of the performance and independence of the independent auditors.

21) Maintain Flexibility. The Committee, in carrying out its responsibilities, policies and procedures should remain flexible, in order to best react to changing conditions and circumstances.

Meetings

The Committee shall meet in person or telephonically at least quarterly, or more frequently as it may determine necessary, to comply with its responsibilities as set forth herein. The Chair of the Committee will, in consultation with the other members of the Committee, the Company s independent auditors and the appropriate officers of the Company, establish the agenda for each Committee meeting. Any Committee member may submit items to be included on the agenda. Committee members may also raise subjects that are not on the agenda at any meeting. The Committee Chair or a majority of the Committee members may call a meeting of the Committee at any time. A majority of the number of Committee members selected by the Board will constitute a quorum for conducting business at a meeting of the Committee. The act of a majority of Committee members present at a Committee meeting at which quorum is in attendance will be the act of the Committee, unless a greater number is required by law, the Company s certificate of incorporation or its by-laws. Any Committee member may be excused from a meeting to permit the remaining members of the Committee to act on any matter in which such member s participation is not appropriate, and such member s absence shall not destroy the quorum for the meeting. The Committee also may take action by unanimous written consent. The Committee Chair will supervise the conduct of the meetings and will have other responsibilities as the Committee may specify from time to time.

The Committee may request any officer or employee of the Company or any representative of the Company s legal counsel or independent auditors or other advisors to attend a meeting of the Committee or to meet with any members, or representatives of the Committee. The Committee shall meet with the Company s management, the internal auditors and the independent auditors periodically in separate private sessions to discuss any matter that the Committee, management, the independent auditors or such other persons believe should be discussed privately.

Resources and Authority

The Committee shall have appropriate resources and authority to discharge its responsibilities as required by law, including the authority to engage independent legal counsel and other advisors as the Committee deems necessary to carry out its responsibilities. The Committee may also, to the extent it deems necessary or appropriate, meet with the Company s investment bankers or financial analysts who follow the Company.

The Company will provide for appropriate funding, as determined by the Committee, for payment of compensation (i) to the Company s independent auditors engaged for the purpose of rendering or issuing an audit report or related work or performing other audit, review or attest services for the Company, and (ii) to independent counsel or any other advisors employed by the Committee.

Audit Committee Report

The Committee will prepare, with the assistance of management, the independent auditors and legal counsel, the Audit Committee Report.

Annual Review

In 2004 and annually thereafter, the Committee shall (a) review this Charter with the Board and recommend any changes to the Board and (b) evaluate its performance against the requirements of this Charter and review this evaluation with the Board. The Committee shall conduct its review and evaluation in such manner as the Committee, in its business judgment, deems appropriate.

Consistent with New York Stock Exchange listing requirements, this Charter will be included on the Company s website and will be made available upon request sent to the Company s Corporate Secretary. The Company s annual report to stockholders will state that this Charter is available on the Company s website and will be available upon request sent to the Company s Corporate Secretary.

March 2005

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OG&E

OGE Energy Corp.

2004 Management s Discussion and Analysis

Appendix A to the Proxy Statement

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 management of 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 and 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 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. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership (NOARK), Enogex also owns a controlling interest in and operates Ozark Gas Transmission, L.L.C. (Ozark), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex was previously engaged in the exploration and production of natural gas, however, this portion of Enogex s business, along with interests in certain gas gathering and processing assets in Texas, was sold in 2002 and in the first quarter of 2003 and are reported in the Consolidated Financial Statements as discontinued operations.

Executive Overview

In early 2002, the Company completed a review of its business strategy that was largely driven by the anticipated deregulation of the retail electric markets in Oklahoma and Arkansas. Due to a variety of factors, the Company recognized that immediate deregulation of the retail electric markets in Oklahoma and Arkansas was very unlikely and revised its business strategy. In the summer of 2004, the Company again reviewed its business strategy in light of significant changing market and regulatory trends such as the over supply of electric generation, the evolution of electric transmission markets and rules, the natural gas supply forecast, the sustained increase of natural gas commodity prices and the anticipated emergence of liquefied natural gas. The Company concluded that its existing business strategy of utilizing a diversified asset position was the proper course.

During 2004, the Company had several significant accomplishments including the completion of the acquisition of a 77 percent interest in the 520 megawatt (MW) NRG McClain Station (the

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McClain Plant) in July 2004, the completion of two revolving credit agreements totaling $550 million for the Company and OG&E in October 2004, improved financial performance at Enogex, improved financial flexibility associated with the reduction of the long-term debt balance at Enogex, such that Enogex began to contribute to funding the Company s dividend which has been funded solely by OG&E in the past. Looking at 2005, OG&E expects to file a rate case during the second quarter of 2005 to recover, among other things, its investment in, and the operating expenses of, the McClain Plant and expects new approved rates to be in effect by January 2006. Also, during 2005, OG&E will work to advance its Customer Savings and Reliability Plan which provides for increased investment at the utility to improve reliability and meet load growth, replace infrastructure equipment and deploy newer technology that improves operational and environmental performance. Capacity payment savings from reduced cogeneration payments and fuel savings from the McClain Plant will be utilized to mitigate the price increases associated with these investments. For additional information regarding the McClain Plant acquisition and related regulatory matters, see Note 18 of Notes to Consolidated Financial Statements. During 2005, the Company will also be focused on controlling and managing operating and maintenance expenses and will continue to analyze the cost structure of the Company s businesses ensuring consistency with the Company s business model. At Enogex during 2005, the Company will focus on enhancing its financial position and the operations of its mid-continent assets as well as seeking to expand into other geographic areas outside of the mid-continent area. Overall, the Company has a strong commitment to train and retain talented personnel so that both the Company and its employees are successful in improving the financial and operating performance of the Company.

The Company s vision is to be a regional energy company focused on its regulated utility business and natural gas pipeline business that is recognized for operational excellence and financial performance. 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 normalized basis, a dividend payout ratio below 75 percent and an A- credit rating.

At Enogex, the Company 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. Enogex s marketing business, which concentrates principally on origination of physical sales of natural gas, has expanded into the Gulf Coast, Rocky Mountain and East Coast markets.

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 focus on those products and services with limited or manageable commodity exposure. The Company intends for OG&E to continue as a vertically integrated utility engaged in the generation, transmission and distribution of electricity and to represent over time approximately 70 percent of the Company s consolidated assets. The remainder of the Company s consolidated assets will be in Enogex s businesses. At December 31, 2004, OG&E and Enogex represented approximately 63 percent and 36 percent, respectively, of the Company s consolidated assets. The remaining one percent of the Company s consolidated assets were primarily at the holding company. 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 subject to the

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evolving federal regulations of the FERC in regard to the operations of the wholesale power market. In addition, Oklahoma and Arkansas legislatures and utility commissions may propose changes from time to time that could subject utilities to market risk. Accordingly, the Company is applying risk management practices to all of its operations in an effort to mitigate the potential adverse effect of any future regulatory changes.

OG&E has approximately 430 MWs of contracts with qualified cogeneration facilities and small power production producers (QF contracts) that will expire at the end of 2007, unless extended by OG&E. In addition, effective September 1, 2004, OG&E entered into a new 15-year power sales agreement for 120 MWs with PowerSmith Cogeneration Project, L.P. (PowerSmith). OG&E will continue reviewing all of the supply alternatives to these expiring 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. Accordingly, OG&E will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, OG&E will also assess the feasibility of constructing additional base load coal-fired units.

Enogex initiated a program in 2002 to improve its financial profile and performance. Since January 1, 2002, Enogex has completed significant sales transactions which have generated net sales proceeds of approximately $106.3 million, reduced debt by approximately $226.8 million or 30.6 percent, reduced its number of employees by approximately 12 percent, reorganized its operations and restructured its senior management team. In addition to focusing on growing its earnings, Enogex managed its commodity price and earnings volatility exposures and minimized its exposure to keep-whole processing arrangements. Enogex s profitability increased significantly in 2003 and 2004 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.

In addition, Enogex is seeking to diversify its gathering, processing and transportation businesses principally by expanding into other geographic areas that are complementary with the Company s strategic capabilities. Enogex s marketing business, which concentrates principally on origination of physical sales of natural gas, has expanded into the Gulf Coast, Rocky Mountain and East Coast markets.

In addition to these ongoing efforts, in 2003 Enogex began a major upgrade of its information systems that is expected to be substantially completed during the second and third quarters of 2005. Enogex believes that these upgrades will be 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.

During 2004, Enogex made improvements to the Stuart Storage Facility which reduced water encroachment in the field. During 2004, approximately $1.9 million in capital expenditures was spent on this project. Enogex does not expect any material future expenditures on this water encroachment project.

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Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in 2005 Outlook , 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 , objecti plan , possible , potential and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures; the Company s ability and the ability of its subsidiaries to obtain financing on favorable terms; prices of electricity, 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; federal or state legislation and regulatory decisions (the proceeding currently pending before the OCC related to OG&E s recovery of the costs billed to it by Enogex for gas transportation and storage services) and initiatives that affect cost and investment recovery, have an impact on rate structures and 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; 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.

Overview

Summary of Operating Results

2004 compared to 2003. The Company reported net income of approximately $153.5 million, or $1.73 per diluted share, as compared to approximately $129.8 million, or $1.58 per diluted share, for the years ended December 31, 2004 and 2003, respectively. The increase in net income during 2004 as compared to 2003 was primarily due to:

- o higher gross margins on revenues (gross margin) in Enogex s gathering and processing business primarily due to an overall favorable business environment coupled with higher commodity prices;

- o gains from asset sales; and
- o lower net interest expense.

These increases to net income were partially offset by:

- o lower gross margins at OG&E due to cooler weather in its service territory; and
- o higher operating expenses.

OG&E reported net income of approximately $107.6 million, or $1.22 per diluted share of the Company s common stock, as compared to approximately $115.4 million, or $1.41 per diluted share, for the years ended December 31, 2004 and 2003, respectively. The decrease in net income at OG&E during 2004 as compared to 2003 is described in more detail below.

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Enogex s operations, including discontinued operations, reported net income of approximately $60.7 million, or $0.69 per diluted share of the Company s common stock, as compared to approximately $26.9 million, or $0.33 per diluted share, for the years ended December 31, 2004 and 2003, respectively. The increase in net income at Enogex during 2004 as compared to 2003 is described in more detail below.

The results of the holding company reflect a loss of approximately $0.18 per diluted share and $0.16 per diluted share, respectively, for the years ended December 31, 2004 and 2003. The increased loss is primarily due to an increase in net interest expense due to a write off of approximately $5.9 million of unamortized debt issuance costs for the trust preferred securities which were redeemed at par on October 15, 2004, partially offset by an increase in other income.

The Company s results of operations for the years ended December 31, 2004 and 2003, respectively, include income of approximately $0.5 million, or $0.01 per diluted share, and a loss of approximately $0.4 million, or less than $0.01 per diluted share, from the discontinued operations discussed below. See Results of Operations Enogex Discontinued Operations for a further discussion.

Earnings per share in 2004 as compared to 2003 were affected by a higher amount of common stock outstanding from the Company s equity issuance in August 2003 and the issuance of common stock in 2003 and 2004 pursuant to the Company s Automatic Dividend Reinvestment and Stock Purchase Plan (DRIP/DSPP).

2003 compared to 2002. The Company reported net income of approximately $129.8 million, or $1.58 per diluted share, as compared to approximately $90.8 million, or $1.16 per diluted share, for the years ended December 31, 2003 and 2002, respectively. The increase in net income during 2003 as compared to 2002 was primarily due to:

- o lower impairment charges at Enogex;
- o higher gross margins in all of Enogex s businesses;
- o growth in OG&E s service territory; and
- o lower interest expenses at the holding company.

These increases to net income were partially offset by:

- o lower gross margins at OG&E due to lower electric rates as a result of the $25 million electric reduction that went into effect in Oklahoma on January 6, 2003.

OG&E reported net income of approximately $115.4 million, or $1.41 per diluted share, as compared to approximately $126.1 million, or $1.61 per diluted share, for the years ended December 31, 2003 and 2002, respectively. The decrease in net income during 2003 as compared to 2002 is described in more detail below.

Enogex s operations, including discontinued operations, reported net income of approximately $26.9 million, or $0.33 per diluted share, as compared to a net loss of approximately $21.7 million, or $0.28 per diluted share, for the years ended December 31, 2003 and 2002, respectively. This improvement during 2003 as compared to 2002 is described in more detail below.

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The results of the holding company reflect a loss of approximately $0.16 per diluted share and $0.17 per diluted share for the years ended December 31, 2003 and 2002, respectively, primarily due to lower interest expenses and a higher income tax benefit partially offset by higher other miscellaneous expenses.

The Company s results of operations for the years ended December 31, 2003 and 2002, respectively, include a loss of approximately $0.4 million, or less than $0.01 per diluted share, and income of approximately $9.8 million, or $0.12 per diluted share, from the discontinued operations discussed below. See Results of Operations Enogex Discontinued Operations for a further discussion.

Regulatory Matters and Plant Acquisition

In November 2002, the OCC issued an order containing provisions of an agreed-upon settlement of OG&E s rate case. The terms of this settlement included, among other things, a $25.0 million annual reduction in electric rates and a requirement for OG&E to acquire 400 MWs of electric generation. The rate reduction went into effect January 6, 2003 and the acquisition of a 77 percent interest in the 520 MW McClain Plant was completed on July 9, 2004. The McClain Plant, located near Newcastle, Oklahoma, is a combined cycle unit consisting of two natural-gas fired combustion turbine generators combined with a steam turbine generator. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority. OG&E operates the plant. The purchase price was approximately $160.0 million. OG&E temporarily funded the McClain Plant acquisition with short-term borrowings from the Company. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings. Also, on August 9, 2004, the Company made a capital contribution to OG&E of approximately $153.0 million. For additional information regarding the McClain Plant acquisition and related regulatory matters, see Note 18 of Notes to Consolidated Financial Statements.

2005 Outlook

For 2005, the Company s earnings guidance is $137 million to $147 million of net income, or $1.50 to $1.60 per share, assuming approximately 90.5 million average diluted shares outstanding. The 2005 outlook includes earnings guidance of $106 million to $110 million, or $1.17 to $1.22 per share, at OG&E and $39 million to $43 million, or $0.43 to $0.48 per share, at Enogex, while earnings guidance at the holding company is a loss between $6 million and $8 million, or $0.07 to $0.09 per share. During 2005, the Company expects cash flow from operations of between $323 million and $332 million. In 2005, OG&E plans to increase capital expenditures for electric system reliability upgrades. Additionally, funding for the Company s pension plan is expected to be approximately $37.4 million in 2005. Expected 2005 net income assumes a 38.7 percent effective tax rate.

For 2005, OG&E earnings guidance is $106 million to $110 million, or $1.17 to $1.22 per share. OG&E assumes that margin growth approximating one to two percent will be more than offset by increased operating expenses and higher interest costs associated with the acquisition of the McClain Plant and capital expenditures for investment in OG&E s generation, transmission and distribution system. OG&E expects to increase capital expenditures to approximately $248 million for electric system expansion and reliability upgrades in 2005. Key factors affecting OG&E s 2005 net income will be the result of pending regulatory proceedings, weather, OG&E s ability to control operating and maintenance expenses and customer growth. OG&E has significant seasonality in its earnings. OG&E typically shows minimal earnings or slight losses in the first and fourth quarters with

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a majority of earnings in the third quarter due to the seasonal nature of air conditioning demand. The earnings guidance further assumes no change in base rates and normal weather. OG&E expects to file a rate case during the second quarter of 2005 to recover, among other things, its investment in, and the operating expenses of, the McClain Plant and expects new approved rates to be in effect by January 2006. The earnings guidance also assumes a recovery of the costs associated with the Enogex natural gas transportation and storage services at a level consistent with a recent recommendation by the administrative law judge overseeing this proceeding. On October 22, 2004, the administrative law judge overseeing the proceeding recommended approximately $41.9 million annual demand fee recovery with OG&E refunding to its customers any amounts collected in excess of this amount. If this recommendation is ultimately accepted, OG&E believes its refund obligation would be approximately $6.9 million at December 31, 2004, which the Company does not believe is material in light of previously established reserves. An OCC order in this case is expected in the first quarter of 2005. There can be no guarantee that the OCC will approve the $41.9 million annual demand fee recovery recommended by the administrative law judge. See Note 18 of Notes to Consolidated Financial Statements for a further discussion of this matter.

For 2005, Enogex earnings guidance is $39 million to $43 million, or $0.43 to $0.48 per share. Enogex manages its operations along three related businesses: transportation and storage; gathering and processing; and marketing. In 2005, these businesses are assumed to produce a gross margin of approximately $269 million, down from $301 million in 2004. The Company expects approximately 46 percent of Enogex s gross margin during 2005 to be generated from its transportation and storage business as compared to 46 percent in 2004. Approximately 88 percent of these gross margins are under firm contracts. Revenues in transportation and storage are primarily from gas transportation contracts with utilities in Oklahoma and Arkansas and independent power producers (IPP) in Oklahoma. Revenues in the transportation and storage business are expected to decrease due to the completion in 2004 of the over recovery of prior year s under recovered fuel. The Company expects its gathering and processing business to contribute approximately 48 percent of Enogex s gross margin in 2005 as compared to 46 percent in 2004. Revenues in gathering and processing are expected to increase in 2005 primarily due to continued efforts to increase margins from the negotiation of both new contracts and replacement contracts. Volumes are expected to remain flat from 2004. The Company has assumed lower commodity spreads of $1.53 per Million British thermal unit (MMBtu) in 2005 as compared to $2.45 per MMBtu in 2004 and has assumed lower average natural gas liquids prices of $0.71 per gallon in 2005 as compared to $0.72 per gallon in 2004. The Company also assumes 242 new well connects in its gathering and processing business in 2005. While operating improvements allowed Enogex to capture significant value in a favorable commodity environment, the commodity and well connect assumptions budgeted for 2005 reflect commodity prices that are not as robust as those experienced in 2004. The Company expects its marketing business to contribute approximately six percent of Enogex s gross margin in 2005 as compared to eight percent in 2004. Gross margins in marketing are expected to decrease in 2005 primarily due to 2004 gross margins being above expectations and its anticipated loss of approximately $3.0 million due to its position on the Cheyenne Plains Pipeline as explained in Note 17 of Notes to Consolidated Financial Statements. Enogex also expects approximately $5.1 million in lower operating expenses in 2005 due to not having an $8.6 million impairment charge that was recorded in the third quarter of 2004. In addition, Enogex also expects approximately $1.2 million in lower net interest expense from the retirement of long-term debt in 2004 and 2005. Key factors affecting Enogex s 2005 net income will be new well connections, natural gas and natural gas liquids prices and operating costs. 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 determined or included in the 2005 earnings guidance.

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For 2005, earnings guidance at the holding company, which primarily has interest expense but no operating revenue, is a loss between $6 million and $8 million, or $0.07 to $0.09 per share. The decrease in the loss as compared to 2004 is primarily due to lower interest expenses associated with the redemption of $200 million of trust preferred securities on October 15, 2004.

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 approximately 75 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. While the dividend payout ratio is expected to exceed the target payout ratio in 2005, management after considering estimates of future earnings and numerous other factors, expects at this time that it will continue to recommend to the Board of Directors a continuance of the current dividend rate.

Results of Operations

The following discussion and analysis presents factors which affected the Company s consolidated results of operations for the years ended December 31, 2004, 2003 and 2002 and the Company s consolidated financial position at December 31, 2004 and 2003. 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.

Enogex previously was engaged in the exploration and production of natural gas (the E&P business). Since January 1, 2002, Enogex has sold all of its E&P business along with certain gas gathering and processing assets that were owned by Enogex through its interest in the NuStar Joint Venture (NuStar) and its interest in Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership (Belvan). As required by accounting principles generally accepted in the United States, these dispositions have been reported as discontinued operations for the years ended December 31, 2004, 2003 and 2002 in the Consolidated Financial Statements.

(In millions, except per share data)	**2004**	2003	2002
Operating income	**$ 317.5**	$ 306.9	$ 235.7
Net income	**$ 153.5**	$ 129.8	$ 90.8
Basic average common shares outstanding	**88.0**	81.8	78.1
Diluted average common shares outstanding	**88.5**	82.1	78.2
Basic earnings per average common share	**$ 1.74**	$ 1.59	$ 1.16
Diluted earnings per average common share	**$ 1.73**	$ 1.58	$ 1.16
Dividends declared per share	**$ 1.33**	$ 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. Included in 2004, 2003 and 2002 operating income are pre-tax impairment charges of approximately $7.8 million, $10.2 million and $50.1 million, respectively. These

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impairments, primarily for Enogex natural gas processing and compression assets that were no longer needed in Enogex s business, were made in accordance with accounting principles generally accepted in the United States.

Operating Income (Loss) by Business Segment

(In millions)	**2004**	2003	2002
OG&E (Electric Utility)	**$ 192.0**	$ 216.2	$ 239.1
Enogex (Natural Gas Pipeline) (A)	**126.6 (B)**	91.2 (B)	(3.0) (B)
Other Operations (C)	**(1.1)**	(0.5)	(0.4)
Consolidated operating income	**$ 317.5**	$ 306.9	$ 235.7

(A) Excludes discontinued operations. See Enogex - Discontinued Operations for a further discussion.
(B) After recording pre-tax impairment charges of approximately $7.8 million, $9.2 million and $48.3 million 2004, 2003 and 2002, respectively.
(C) Other Operations primarily includes unallocated corporate expenses.

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

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OG&E

(Dollars in millions)	**2004**	2003	2002
Operating revenues	**$ 1,578.1**	$ 1,517.1	$ 1,388.0
Fuel	**645.4**	544.5	435.8
Purchased power	**269.1**	292.9	260.0
Gross margin on revenues	**663.6**	679.7	692.2
Other operating and maintenance	**301.9**	294.8	282.9
Depreciation	**122.7**	121.8	123.1
Taxes other than income	**47.0**	46.9	47.1
Operating income	**$ 192.0**	$ 216.2	$ 239.1
Operating revenues by classification			
Residential	**$ 611.4**	$ 601.4	$ 557.6
Commercial	**389.9**	372.5	346.9
Industrial	**326.7**	293.4	258.6
Public authorities	**158.5**	146.1	135.5
Sales for resale	**57.0**	57.7	48.2
Provision for refund on gas transportation and storage case	**(6.9)**	---	---
Other	**40.7**	41.9	34.9
System sales revenues	**1,577.3**	1,513.0	1,381.7
Off-system sales revenues	**0.8**	4.1	6.3
Total operating revenues	$ **1,578.1**	$ 1,517.1	$ 1,388.0

MWH (A) sales by classification (in millions)			
Residential	**7.9**	8.2	8.0
Commercial	**5.7**	5.8	5.8
Industrial	**7.0**	6.8	6.6
Public authorities	**2.7**	2.7	2.7
Sales for resale	**1.4**	1.5	1.5
System sales	**24.7**	25.0	24.6
Off-system sales	**0.1**	0.1	0.3
Total sales	**24.8**	25.1	24.9
Number of customers	**735,008**	725,470	718,513
Average cost of energy per KWH (B) - cents			
Fuel	**2.887**	2.454	1.897
Fuel and purchased power	**3.436**	3.128	2.614
Degree days (C)			
Heating			
Actual	**3,114**	3,488	3,753
Normal	**3,650**	3,631	3,634
Cooling			
Actual	**1,839**	1,898	1,847
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 above 65 degrees, then the difference between the calculated average and 65 is expressed as cooling degree days, with each degree of difference equaling one cooling degree day. If the calculated average is below 65 degrees, then the difference between the calculated average and 65 is expressed as heating degree days, with each degree of difference equaling one heating degree day. The daily calculations are then totaled for the particular reporting period.

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2004 compared to 2003. OG&E s operating income decreased approximately $24.2 million or 11.2 percent in 2004 as compared to 2003. The decrease in operating income was primarily attributable to:

- lower gross margins due to cooler weather in OG&E s service territory;
- lower margins related to sales to wholesale customers;
- the timing of fuel recoveries; and
- higher operating expenses.

These decreases in operating income were partially offset by:

- growth in OG&E s service territory.

Gross margin, which is operating revenues less cost of goods sold, was approximately $663.6 million in 2004 as compared to approximately $679.7 million in 2003, a decrease of approximately $16.1 million or 2.4 percent. The gross margin decreased primarily due to:

- cooler weather in OG&E s service territory which reduced the gross margin by approximately $15.7 million;
- lower margins related to sales to wholesale customers primarily resulting from reduced sales of power under a new wholesale contract with an existing customer which reduced the gross margin by approximately $3.2 million; and

- o the timing of fuel recoveries which decreased the gross margin by approximately $1.7 million.

These decreases in gross margin were partially offset by:

- o growth in OG&E s service territory which increased the gross margin by approximately $4.9 million.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $645.4 million in 2004 as compared to approximately $544.5 million in 2003, an increase of approximately $100.9 million or 18.5 percent. The increase was primarily due to an increase in the average cost of fuel per kwh, primarily due to higher natural gas prices despite lower mwh sales. 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 2004, OG&E s fuel mix was 70 percent coal and 30 percent natural gas as compared to 77 percent coal and 23 percent natural gas in 2003. Though OG&E has a higher installed capability of generation from natural gas units of 59 percent, it has been more economical to generate electricity for our customers with lower priced coal. Purchased power costs were approximately $269.1 million in 2004 as compared to approximately $292.9 million in 2003, a decrease of approximately $23.8 million or 8.1 percent. The decrease was primarily due to OG&E s acquisition of the McClain Plant in July 2004 and the termination of power purchase contracts in December 2003 and August 2004.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E s customers through automatic fuel adjustment clauses. While the regulatory mechanisms for recovering fuel costs differ in Oklahoma, Arkansas and the FERC, in each jurisdiction

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the costs are passed through to customers and are intended to provide neither an ultimate benefit nor detriment to OG&E. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex. See Note 18 of Notes to Consolidated Financial Statements for a discussion of current proceedings at the OCC regarding OG&E s gas transportation and storage contract with Enogex.

Other operating and maintenance expenses were approximately $301.9 million in 2004 as compared to approximately $294.8 million in 2003, an increase of approximately $7.1 million or 2.4 percent. The increase in other operating and maintenance expenses was primarily due to:

- o increased outside services expense of approximately $17.9 million, primarily due to higher expenses for infrastructure projects in the fourth quarter of 2004, many of which were postponed from earlier in 2004;
- o increased materials and supplies expense of approximately $1.8 million; and
- o increased liability insurance expense of approximately $0.9 million due to increased insurance premiums.

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

- o lower salaries and wages expense of approximately $6.8 million and lower pension and benefit expense of approximately $6.6 million primarily due to more projects on which the costs are capitalized and are not being expensed currently.

Depreciation expense was approximately $122.7 million in 2004 as compared to approximately $121.8 million in 2003, an increase of approximately $0.9 million or 0.7 percent, primarily due to a higher level of depreciable plant. Also, another factor affecting 2004 results was an overall increase of approximately $3.8 million in the reserves related to litigation.

2003 compared to 2002. OG&E s operating income decreased approximately $22.9 million or 9.6 percent in 2003 as compared to 2002. The decrease in operating income was primarily attributable to:

- o lower electric rates as a result of the $25 million electric rate reduction that went into effect in Oklahoma on January 6, 2003;
- o weaker weather-related demand;
- o lower sales to other utilities and power marketers (off-system sales); and
- o higher other operating and maintenance expenses.

These decreases in operating income were partially offset by:

- o growth in OG&E s service territory.

Gross margin was approximately $679.7 million in 2003 as compared to approximately $692.2 million in 2002, a decrease of approximately $12.5 million or 1.8 percent. The gross margin decreased primarily due to:

- o lower electric rates as a result of the $25 million electric rate reduction that went into effect in Oklahoma on January 6, 2003, which reduced the gross margin by approximately $24.8 million;
- o weaker weather-related demand which reduced the gross margin by approximately $2.0 million; and
- o lower off-system sales which reduced the gross margin by approximately $1.9 million as off-system sales can vary based upon the supply and demand needs on OG&E s generation system and the market for off-system sales.

These decreases in gross margin were partially offset by:

- o growth in OG&E s service territory which increased the gross margin by approximately $17.5 million.

Fuel expense was approximately $544.5 million in 2003 as compared to approximately $435.8 million in 2002, an increase of approximately $108.7 million or 24.9 percent. The increase was due to a 29.4 percent increase in the average cost of fuel per kwh, primarily due to higher natural gas prices and higher mwh sales. 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 2003, OG&E s fuel mix was 77 percent coal and 23 percent natural gas. Purchased power costs were approximately $292.9 million in 2003 as compared to approximately $260.0 million in 2002, an increase of approximately $32.9 million or 12.7 percent. The increase was primarily due to approximately a 28.2 percent increase in the volume of energy purchased primarily due to economic purchases.

Other operating and maintenance expenses were approximately $294.8 million in 2003 as compared to approximately $282.9 million in 2002, an increase of approximately $11.9 million or 4.2 percent. The increase in other operating and maintenance expenses was primarily due to:

- o higher pension and benefit expenses of approximately $10.7 million due to the general upward trend in these costs; and
- o costs of approximately $5.4 million incurred during the first quarter of 2002 in connection with the severe January 2002 ice storm being reported as a regulatory asset as these 2002 expenditures, incurred by field service personnel, would normally have been charged to maintenance expenses in 2002.

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

- o lower uncollectibles expense of approximately $3.5 million due to improved collection efforts.

Depreciation expense was approximately $121.8 million in 2003 as compared to approximately $123.1 million in 2002, a decrease of approximately $1.3 million or 1.1 percent, primarily due to a change made in the depreciation rate of production plant in 2003 as required by the settlement of OG&E s rate case in November 2002 (the Settlement Agreement).

Enogex Continuing Operations

(Dollars in millions)	**2004**	2003	2002

Operating revenues	**$ 3,443.9**	$ 2,327.8	$ 1,684.0
Gas and electricity purchased for resale (A)	**3,054.3**	2,019.1	1,402.1
Natural gas purchases - other	**88.6**	55.4	70.5
Gross margin on revenues	**301.0**	253.3	211.4
Other operating and maintenance	**101.5**	91.2	101.1
Depreciation	**47.6**	44.2	49.3
Impairment of assets	**7.8**	9.2	48.3
Taxes other than income	**17.5**	17.5	15.7
Operating income (loss)	**$ 126.6**	$ 91.2	$ (3.0)
New well connects	**277**	232	166
Gathered volumes - TBtu/d (B)	**1.01**	0.99	1.06
Incremental transportation volumes - TBtu/d	**0.51**	0.44	0.49
Total throughput volumes - TBtu/d	**1.52**	1.43	1.55
Natural gas processed - Mmcf/d (C)	**502**	414	455
Natural gas liquids sold (keep whole) - million gallons	**263**	207	285
Natural gas liquids sold (POL and fixed-fee) - million gallons	**16**	18	22
Total natural gas liquids sold - million gallons	**279**	225	307
Average sales price per gallon	**$ 0.720**	$ 0.595	$ 0.406

(A) OGE Energy Resources, Inc. (OERI) exited the power marketing business during the first quarter of 2004.
(B) Trillion British thermal units per day.
(C) Million cubic feet per day.

2004 compared to 2003. Enogex s operating income in 2004 increased approximately $35.4 million or 38.8 percent as compared to 2003. The increase in operating income was primarily attributable to higher gross margins in Enogex s gathering and processing business primarily due to an overall favorable business environment coupled with higher commodity prices and revenue improvements generated from the negotiation of both new contracts and replacement contracts at better terms. These increases were partially offset by higher operating expenses.

Enogex sold its interest in NuStar during the first quarter of 2003; accordingly this is reported as discontinued operations for the years ended December 31, 2004, 2003 and 2002 in the Consolidated Financial Statements. See Enogex Discontinued Operations for a further discussion.

Transportation and storage contributed approximately $137.4 million of Enogex s gross margin in 2004 as compared to approximately $138.1 million in 2003, a decrease of approximately $0.7 million or 0.5 percent. The gross margin decreased primarily due to:

- certain contractual revenues recorded in transportation and storage in 2003 being recorded in gathering and processing in 2004 which reduced the gross margin by approximately $12.7 million;
- mark-to-market timing losses on natural gas storage inventory which reduced the gross margin by approximately $3.7 million;
- the Calpine Energy Services, L.P. (Calpine Energy) settlement in 2003 which resulted in a one-time increase of approximately $2.0 million to the gross margin in 2003;

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- the net change between fuel retained and fuel consumed which decreased the gross margin by approximately $1.7 million; and
- third party pipeline imbalances which decreased the gross margin by approximately $1.0 million.

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

- o higher purchases and sales activity due to Enogex being more active in the marketplace which increased the gross margin by approximately $6.6 million;
- o higher interruptible revenues and higher crosshaul revenues due to an increase in interruptible contract volumes and increased crosshaul margins and volumes which increased the gross margin by approximately $6.3 million;
- o higher transportation and storage revenues in 2004 primarily due to the additional demand fees and overrun charges from the transportation and storage contract with OG&E, which was effective May 2003, which increased the gross margin by approximately $4.9 million; and
- o an amended intercompany natural gas purchase contract which increased the gross margin by approximately $2.5 million.

Gathering and processing contributed approximately $139.8 million of Enogex s gross margin in 2004 as compared to approximately $91.3 million in 2003, an increase of approximately $48.5 million or 53.1 percent. Gathering gross margins increased approximately $27.5 million in 2004 as compared to 2003 primarily due to:

- o the change in 2004 discussed above of recording certain contractual revenues in gathering and processing rather than in transportation and storage, which increased the gross margin by approximately $12.7 million;
- o revenue improvements generated from an overall favorable business environment coupled with higher commodity prices and the negotiation of both new contracts and replacement contracts at better terms; and
- o an increase in the number of well connects and the volumes of natural gas gathered.

Processing gross margins increased approximately $21.0 million in 2004 as compared to 2003 primarily due to:

- o increased keep-whole, percent of liquids and condensate margins due to favorable commodity prices and higher keep-whole volumes which increased the gross margin by approximately $21.9 million; and
- o an expense reallocation of compressor fuel (from processing in 2003 to transportation and storage in 2004) which increased the gross margin by approximately $1.3 million.

Marketing contributed approximately $23.8 million of Enogex s gross margin in 2004 as compared to approximately $23.9 million in 2003, a decrease of approximately $0.1 million or 0.4 percent. The gross margin decreased primarily due to:

- o lower gains from the sale of natural gas in storage in 2004 of approximately $12.1 million primarily due to Enogex recording approximately a $9.0 million pre-tax loss as a cumulative effect of a change in accounting principle in the first quarter of 2003 rather

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than recording this loss as a reduction of the gross margin. The cumulative effect of a change in accounting principle was the result of accounting for certain energy contracts and natural gas in storage at the lower of cost or market rather than on a mark-to-market basis (see Note 2 of Notes to Consolidated Financial Statements for a further discussion);
- o mark-to-market timing losses on natural gas storage inventory due to different pricing environments during 2004 as compared to 2003 which reduced the gross margin by approximately $2.2 million; and
- o exiting the power marketing business in 2004 which reduced the gross margin by approximately $1.1 million.

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

- o new business activity in the marketing portfolio which increased the gross margin by approximately $12.2 million; and
- o lower demand fees expense for storage services due to establishing new rates for the new storage season which began April 1 which increased the gross margin by approximately $3.4 million.

Enogex s other operating and maintenance expenses were approximately $101.5 million in 2004 as compared to approximately $91.2 million in 2003, an increase of approximately $10.3 million or 11.3 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher payroll, benefit and pension expenses of approximately $4.1 million due to hiring new employees, payment of overtime and salary increases;
- higher outside service costs of approximately $2.4 million related to work performed to maintain the integrity and safety of Enogex s pipeline;
- higher materials and supplies expense of approximately $2.3 million for repairs and maintenance of systems; and
- higher uncollectibles expense of approximately $1.4 million due to miscellaneous accounts receivable items becoming over 180 days old.

Depreciation expense was approximately $47.6 million in 2004 as compared to approximately $44.2 million in 2003, an increase of approximately $3.4 million or 7.7 percent. The increase was primarily due to a higher level of depreciable plant as the implementation of an information system was completed during the second quarter of 2004 in addition to accelerated depreciation recorded during the fourth quarter of 2004 related to the impairment involving four of Enogex s non-contiguous pipeline asset segments.

Impairment of assets was approximately $7.8 million in 2004 as compared to approximately $9.2 million in 2003, a decrease of approximately $1.4 million or 15.2 percent. 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 connection with the preparation of the third quarter 2004 financial statements, Enogex performed an evaluation on these assets and concluded that an impairment charge needed to be recorded. The primary reason for this determination was that these four pipeline asset segments were originally built for the specific purpose of providing gas transmission service to this customers four power plants that have been or are in the

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process of being shut down, and, as a result, other alternative commercial uses for these facilities are considered unlikely. Also, in 2004, the Company reclassified several compressors and processing plants that were previously classified as assets held for sale to assets held and used. This decision was based on the fact these assets are no longer being marketed and the Company believes the value of the future benefit of holding these assets exceeds the current fair market value. As a result, in accordance with Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long Lived Assets, the Company determined the fair value of these assets based on a third party valuation of the assets and, as a result, the Company recorded a net gain of approximately $0.8 million during 2004 related to reclassifying these assets from assets held for sale to assets held and used, which was recorded as a credit to Impairment of Assets on the Consolidated Statements of Income. During 2003, an evaluation of the horsepower of compression needed to meet the operational requirements of the Company s gathering and transmission system was performed based on the then current market conditions. The review identified compressor equipment that could be removed from the system and a pre-tax impairment loss of approximately $9.2 million was recorded in the fourth quarter of 2003 to recognize the difference between the carrying value of these units and their fair value expected to be realized in a disposal. The impairment recorded in the fourth quarter of 2003 resulted from plans to dispose of these assets at prices below the carrying amount. The fair value of these assets was determined based on third-party evaluations, prices for similar assets, historical data and projected cash flows.

During the year ended December 31, 2004, Enogex had an increase in net income of approximately $4.9 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:

- 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 $1.5 million;
- a settlement related to a customer bankruptcy of approximately $0.5 million; and
- income from discontinued operations of approximately $0.5 million.

These increases to net income were partially offset by:

- a net impairment charge of approximately $4.8 million.

During the year ended December 31, 2003, Enogex had an increase in net income of approximately $3.6 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:

- o authorized recovery of previously under recovered fuel of approximately $6.5 million;
- o a gain on the sale of assets of approximately $2.6 million;
- o a settlement related to a dispute with Calpine Energy of approximately $1.2 million; and
- o a pricing adjustment on a processing contract with a customer of approximately $1.1 million.

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These increases to net income were partially offset by:

- o an impairment charge of approximately $5.7 million;
- o an income tax adjustment of approximately $1.7 million; and
- o a loss from discontinued operations of approximately $0.4 million.

2003 compared to 2002. Enogex s operating income in 2003 increased approximately $94.2 million as compared to 2002. The increase in operating income was primarily attributable to:

- o lower impairment charges;
- o higher gross margins in all of Enogex s businesses, from among other things, improved management of pipeline system fuel, increased levels of firm transportation revenues, improved processing results and the negotiation of both new contracts and replacement contracts at better terms; and
- o lower operating and maintenance expenses.

Enogex sold its E&P business and its interest in Belvan during 2002 and Enogex sold its interest in NuStar during the first quarter of 2003; accordingly, these are reported as discontinued operations for the years ended December 31, 2003 and 2002 in the Consolidated Financial Statements. See Enogex Discontinued Operations for a further discussion.

Transportation and storage contributed approximately $138.1 million of Enogex s gross margin in 2003 as compared to approximately $120.8 million in 2002, an increase of approximately $17.3 million or 14.3 percent. The gross margin increased primarily due to:

- o improved management of pipeline system fuel which, when coupled with higher natural gas prices, accelerated the authorized recovery of pipeline system fuel expense, which was the result of Enogex under recovering fuel in prior periods which increased the gross margin by approximately $11.8 million;
- o higher storage revenues primarily due to new demand fees from the contract with OG&E related to the purchase of the Stuart Storage Facility in August 2002 and increased demand fees from both third parties and Enogex s marketing business which increased the gross margin by approximately $8.8 million; and
- o higher levels of firm transportation revenues as a result of the Calpine Energy settlement and an increase in related demand fees recognized in 2003 which collectively increased the gross margin by approximately $5.7 million.

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

- o lower interruptible revenues related to bundled contracts due to a revenue reallocation (from Enogex s transportation and storage business to Enogex s gathering and processing business) to more accurately reflect the performance of Enogex businesses which reduced the gross margin by approximately $2.8 million;
- o higher electric compression costs which reduced the gross margin by approximately $1.2 million; and
- o an imbalance collectibility reserve which reduced the gross margin by approximately $1.2 million.

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Gathering and processing contributed approximately $91.3 million of Enogex s gross margin in 2003 as compared to approximately $73.0 million in 2002, an increase of approximately $18.3 million or 25.1 percent. Gathering gross margins increased approximately $9.8 million in

2003 as compared to 2002 primarily due to:

- o higher interruptible revenues related to bundled contracts due to a revenue reallocation related to bundled contracts (from Enogex s transportation and storage business to Enogex s gathering and processing business) to more accurately reflect the performance of Enogex s businesses which increased the gross margin by approximately $2.8 million;
- o revenue improvements generated from the negotiation of both new contracts and replacement contracts at better terms; and
- o an increase in the number of well connects.

Processing gross margins increased approximately $8.5 million in 2003 as compared to 2002 primarily due to:

- o wider commodity spreads between natural gas and natural gas liquids; and
- o better management and dispatch of the plants; however, processing volumes were lower as a result of economic dispatching of the network of processing plants based upon market conditions.

Marketing contributed approximately $23.9 million of Enogex s gross margin in 2003 as compared to approximately $17.6 million in 2002, an increase of approximately $6.3 million or 35.8 percent. The gross margin increased primarily due to:

- o higher gains from the sale of natural gas in storage in 2003 of approximately $10.2 million primarily due to Enogex recording approximately a $9.0 million pre-tax loss as a cumulative effect of a change in accounting principle in the first quarter of 2003 rather than recording this loss as a reduction of the gross margin. The cumulative effect of a change in accounting principle was the result of accounting for certain energy contracts and natural gas in storage at the lower of cost or market rather than on a mark-to-market basis (see Note 2 of Notes to Consolidated Financial Statements for a further discussion).

This increase in the marketing gross margin was partially offset by:

- o higher demand fees expense paid to Enogex s transportation and storage business which reduced the gross margin by approximately $2.2 million; and
- o a change in the timing of revenue recognition related to natural gas in storage under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, in 2003 as compared to mark-to-market accounting in 2002 which reduced the gross margin by approximately $0.9 million. This accounting change was driven by the rescission of mark-to-market accounting for natural gas in storage as a result of Emerging Issues Task Force (EITF) Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, which was issued in October 2002 (see Note 2 of Notes to Consolidated Financial Statements for a further discussion).

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Enogex s other operating and maintenance expenses were approximately $91.2 million in 2003 as compared to approximately $101.1 million in 2002, a decrease of approximately $9.9 million or 9.8 percent. The decrease in other operating and maintenance expenses was primarily due to:

- o lower uncollectibles expense of approximately $4.9 million due to establishing reserves in 2002 related to two customer bankruptcies;
- o lower materials and supplies expense of approximately $4.2 million due to the active use of inventories;
- o lower expense allocations from the parent of approximately $1.6 million due to the closing of two natural gas processing plants in 2003; and
- o lower miscellaneous operating expenses in 2003 due to termination benefits of approximately $0.9 million.

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

- o higher outside service costs of approximately $2.0 million related to work performed to maintain the integrity and safety of Enogex s pipeline as well as the cost of new well connects.

Depreciation expense was approximately $44.2 million in 2003 as compared to approximately $49.3 million in 2002, a decrease of approximately $5.1 million or 10.3 percent. The decrease was primarily the result of ceasing depreciation on the assets written down as of December 31, 2002 due to the Company s decision to sell these assets and classify them as held for sale in the fourth quarter of 2002.

Impairment charges were approximately $9.2 million in 2003 as compared to approximately $48.3 million in 2002, a decrease of approximately $39.1 million or 81.0 percent. The impairment charges in 2003 and 2002 related to certain idle Enogex natural gas compression assets.

Taxes other than income were approximately $17.5 million in 2003 as compared to approximately $15.7 million in 2002, an increase of approximately $1.8 million or 11.5 percent. The increase was the result of higher ad valorem taxes.

During the year ended December 31, 2003, Enogex had an increase in net income of approximately $3.6 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:

- o authorized recovery of previously under recovered fuel of approximately $6.5 million;
- o a gain on the sale of assets of approximately $2.6 million;
- o a settlement related to a dispute with Calpine Energy of approximately $1.2 million; and
- o a pricing adjustment on a processing contract with a customer of approximately $1.1 million.

These increases to net income were partially offset by:

- o an impairment charge of approximately $5.7 million;
- o an income tax adjustment of approximately $1.7 million; and
- o a loss from discontinued operations of approximately $0.4 million.

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During the year ended December 31, 2002, Enogex had a decrease in net income of approximately $26.4 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex s business. The decrease in net income includes:

- o an impairment charge of approximately $31.1 million;
- o a reserve for two customer bankruptcies of approximately $2.8 million; and
- o a reserve for unpaid demand fees related to a dispute with Calpine Energy of approximately $2.3 million.

These decreases to net income were partially offset by:

- o income from discontinued operations of approximately $9.8 million.

Consolidated Other Income and Expense, Interest Expense and Income Tax Expense

2004 compared to 2003. Other income includes, among other things, contract work performed by OG&E, non-operating rental income, gain on the sale of assets, minority interest income and miscellaneous non-operating income. Other income was approximately $12.1 million in 2004 as compared to approximately $8.1 million in 2003, an increase of approximately $4.0 million or 49.4 percent. The increase in other income was primarily due to:

- o a realized gain of approximately $3.2 million from the sale of OG&E s interests in its natural gas producing properties;
- o a realized gain of approximately $3.0 million on the sale of certain of Enogex s compression and processing assets;
- o appreciation of investments associated with certain participants contributions in the deferred compensation plan and restoration of retirement income plan of approximately $1.0 million;

- o increased allowance for equity funds used during construction in 2004 of approximately $0.9 million;
- o a bankruptcy settlement from one of the Company s customers of approximately $0.8 million;
- o a realized gain of approximately $0.6 million from the repurchase of outstanding heat pump loans; and
- o a realized gain of approximately $0.3 million from the sale of land and buildings near the Company s principal executive offices.

These increases in other income were partially offset by:

- o a realized gain of approximately $5.3 million related to the sale of approximately 29 miles of transmission lines of the Ozark pipeline in the first quarter of 2003.

Other expense includes, among other things, expenses from the losses on the sale of assets, minority interest expense, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions. Other expense was approximately $5.5 million in 2004 as compared to approximately $9.0 million in 2003, a decrease of approximately $3.5 million or 38.9 percent. The decrease in other expense was primarily due to:

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- o realized losses of approximately $1.3 million from the sale of miscellaneous assets in 2003;
- o minority interest expense of approximately $1.1 million in the first quarter of 2003 related to the gain from the sale of approximately 29 miles of transmission lines of the Ozark pipeline that was attributable to the minority interest; and
- o a loss from the dissolution of a lease in the third quarter of 2003 of approximately $0.7 million.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $90.9 million in 2004 as compared to approximately $96.7 million in 2003, a decrease of approximately $5.8 million or 6.0 percent. The decrease in net interest expense was primarily due to:

- o a reduction in interest expense of approximately $5.0 million due to the reduction and early retirement of long-term debt;
- o an increase in interest income of approximately $3.6 million due to the interest portion of an income tax refund related to prior periods;
- o a reduction in interest expense and commercial paper service fees of approximately $1.6 million due to the Company having a lower average commercial paper balance outstanding in 2004 as compared to 2003; and
- o a reduction in interest expense of approximately $1.1 million due to an increase in the allowance for borrowed funds used during construction.

These decreases in net interest expense were partially offset by:

- o an increase in interest expense of approximately $5.9 million due to the write off of unamortized debt issuance costs for the trust preferred securities; and
- o an increase in interest expense of approximately $0.7 million due to the issuance of long-term debt in November 2004.

Income tax expense was approximately $80.2 million in 2004 as compared to approximately $73.7 million in 2003, an increase of approximately $6.5 million or 8.8 percent. The increase in income tax expense was primarily due to:

- o higher pre-tax income for Enogex.

This increase in income tax expense was partially offset by:

- o lower pre-tax income for OG&E; and

- the recognition of additional Oklahoma state tax credits of approximately $4.1 million during 2004.

2003 compared to 2002. Other income was approximately $8.1 million in 2003 as compared to approximately $3.7 million in 2002, an increase of approximately $4.4 million. The increase in other income was primarily due to:

- a realized gain of approximately $5.3 million related to the sale of approximately 29 miles of transmission lines of the Ozark pipeline in the first quarter of 2003.

This increase in other income was partially offset by:

- lower appreciation of investments in 2003 as compared to 2002 associated with certain participants contributions in the deferred compensation plan of approximately $0.9 million.

Other expense was approximately $9.0 million in 2003 as compared to approximately $4.7 million in 2002, an increase of approximately $4.3 million or 91.5 percent. The increase in other expense was primarily due to:

- minority interest expense of approximately $1.1 million in the first quarter of 2003 related to the gain from the sale of approximately 29 miles of transmission lines of the Ozark pipeline that was attributable to the minority interest;
- an increased liability associated with the deferred compensation plan approximately a $1.0 million;
- a loss on the retirement of fixed assets of approximately $0.9 million;
- a loss from the dissolution of a lease in the third quarter of 2003 of approximately $0.7 million; and
- a loss from the sale of the Company s aircraft in the third quarter of 2003 of approximately $0.1 million.

Net interest expense was approximately $96.7 million in 2003 as compared to approximately $109.1 million in 2002, a decrease of approximately $12.4 million or 11.4 percent. The decrease in net interest expense was primarily due to:

- a reduction in interest expense of approximately $7.9 million related to the retirement of $140.0 million of Enogex debt during 2002;
- a reduction in interest expense of approximately $2.5 million due to a lower average commercial paper balance in 2003 as compared to 2002; and
- a reduction in interest expense of approximately $2.3 million related to lower interest rates on outstanding debt achieved from entering into interest rate swap agreements.

Income tax expense was approximately $73.7 million in 2003 as compared to approximately $44.6 million in 2002, an increase of approximately $29.1 million or 65.2 percent. The increase in income tax expense was primarily due to:

- higher pre-tax income for Enogex.

This increase in income tax expense was partially offset by:

- lower pre-tax income for OG&E;
- a greater deduction for the Company s Employee Stock Ownership Plan dividends in 2003, which reduced taxable income as compared to 2002;
- a reversal of previously accrued federal income tax in 2002 related to several issues that were resolved in favor of the Company; and
- an Oklahoma income tax refund in 2002 related to Oklahoma investment tax credits from prior years.

Enogex Discontinued Operations

Enogex sold its interests in Belvan for approximately $9.8 million in March 2002. The Company recognized an after tax gain of approximately $1.6 million related to the sale of these assets.

Enogex sold its exploration and production assets located in Oklahoma, Texas, Arkansas and Mississippi for approximately $15.0 million in August 2002. The Company recognized an after tax gain of approximately $2.3 million related to the sale of these assets.

Enogex sold its exploration and production assets located in Michigan for approximately $32.0 million in November 2002. The Company recognized an after tax gain of approximately $2.9 million related to the sale of these assets.

Enogex sold its interests in NuStar for approximately $37.0 million in February 2003. The Company recognized an after tax gain of approximately $1.4 million related to the sale of these assets in the first quarter of 2003. Following completion of the final accounting for the NuStar sale, the Company recorded an additional charge of approximately $0.2 million after tax in the third quarter of 2003. The final accounting is subject to approval by all parties to the sale of the joint venture interest. During 2004, the Company recognized approximately $0.5 million after tax from funds received related to an overpayment for natural gas purchases in a prior period.

As a result of these sale transactions, Enogex s E&P business, its interest in NuStar and its interest in Belvan, all of which were part of the Natural Gas Pipeline segment, have been reported as discontinued operations for the years ended December 31, 2004, 2003 and 2002 in the Consolidated Financial Statements. Results for these discontinued operations are summarized and discussed below.

(In millions)	**2004**	2003	2002
Operating revenues	**$ 0.8**	$ 7.8	$ 79.5
Gas purchased for resale	**---**	5.9	49.5
Natural gas purchases - other	**---**	0.6	6.4
Gross margin on revenues	**0.8**	1.3	23.6
Other operation and maintenance	**---**	1.1	12.1
Depreciation	**---**	0.2	4.4
Taxes other than income	**---**	0.1	0.6
Operating income (loss)	**0.8**	(0.1)	6.5
Other income	**---**	1.9	1.8
Net interest income	**---**	---	0.1
Income tax expense (benefit)	**0.3**	2.2	(1.4)
Net income (loss)	$ **0.5**	$ (0.4)	$ 9.8

2004 compared to 2003. Following the sale of NuStar in February 2003, no operations of NuStar are reflected in the Consolidated Financial Statements except for approximately $0.8 million received during 2004 related to an overpayment of natural gas purchases in a prior period.

2003 compared to 2002. Gross margin decreased approximately $22.3 million or 94.5 percent in 2003 as compared to 2002. Other operating and maintenance expenses decreased approximately $11.0 million or 90.9 percent, depreciation expense decreased $4.2 million or 95.5 percent and taxes other than income decreased approximately $0.5 million or 83.3 percent in 2003 as compared to 2002. The decreases in the gross margin, other operating and maintenance expenses, depreciation expense

and taxes other than income were attributable to the sale of Enogex s E&P business and Belvan during 2002 and the sale of NuStar in February 2003.

Financial Condition

The balance of Cash and Cash Equivalents was approximately $26.4 million and $245.6 million at December 31, 2004 and 2003, respectively, a decrease of approximately $219.2 million or 89.3 percent. The balance at December 31, 2003 was primarily due to an increase in short-term investments at December 31, 2003 in anticipation of the need for funds to purchase the McClain Plant, which was originally expected to occur by December 31, 2003, and, which was ultimately completed on July 9, 2004.

The balance of Accounts Receivable was approximately $487.9 million and $350.2 million at December 31, 2004 and 2003, respectively, an increase of approximately $137.7 million or 39.3 percent. The increase was primarily due to higher natural gas prices and volumes associated with Enogex s activities in the fourth quarter of 2004 partially offset by improved collection efforts at OG&E.

The balance of Fuel Inventories was approximately $89.0 million and $149.6 million at December 31, 2004 and 2003, respectively, a decrease of approximately $60.6 million or 40.5 percent. The decrease was primarily due to inventory sales at Enogex during 2004.

The balance of current Price Risk Management assets was approximately $118.6 million and $61.3 million at December 31, 2004 and 2003, respectively, an increase of approximately $57.3 million or 93.5 percent. The increase was primarily due to an increase in park and loan transactions, natural gas storage injections and withdrawals and related financial contracts associated with OERI s activities during 2004.

The balance of the Gas Imbalance asset was approximately $100.1 million and $70.0 million at December 31, 2004 and 2003, respectively, an increase of approximately $30.1 million or 43.0 percent. The Gas Imbalance asset is comprised of planned or managed imbalances related to Enogex s marketing 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 $76.0 million and $45.4 million at December 31, 2004 and 2003, respectively, an increase of approximately $30.6 million or 67.4 percent. The increase was due to an increase in park and loan transactions during 2004 resulting from economic opportunities in the marketplace.

The balance of Fuel Clause Under Recoveries was approximately $54.3 million at December 31, 2004. The balance of Fuel Clause Over Recoveries (net of Fuel Clause Under Recoveries) was approximately $28.4 million at December 31, 2003. The increase in fuel clause under recoveries was due to under recoveries from OG&E s customers as OG&E s cost of fuel exceeded the amount billed during 2004. The cost of fuel subject to recovery through the fuel clause mechanism was approximately $2.43 per MMBtu in December 2004, and was approximately $1.21 per MMBtu in December 2003. OG&E s fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers bills. As a result, OG&E under recovers fuel 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. OG&E expects to recover the fuel clause under recoveries during 2005.

The balance of Recoverable Take or Pay Gas Charges was approximately $17.0 million and $32.5 million at December 31, 2004 and 2003, respectively, a decrease of approximately $15.5 million or 47.7 percent. Approximately $21.0 million and $32.5 million have been recorded at December 31, 2004 and 2003, respectively, in the Provision for Payments of Take or Pay Gas classified as Current Liabilities and Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. These amounts represent OG&E s estimate of the maximum amount that it could be obligated to pay under certain take-or-pay contracts. OG&E believes that it is entitled to recover any such amounts from its customers through its regulatorily approved automatic fuel adjustment clauses or other regulatory mechanisms.

The balance of Prepaid Benefit Obligation was approximately $92.7 million and $55.7 million at December 31, 2004 and 2003, respectively, an increase of approximately $37.0 million or 66.4 percent. The increase was primarily due to the Company funding its pension plan during the second and third quarters of 2004 partially offset by pension accruals being credited to the prepaid benefit obligation.

The balance of Short-Term Debt was approximately $125.0 million and $202.5 million at December 31, 2004 and 2003, respectively, a decrease of approximately $77.5 million or 38.3 percent. The balance at December 31, 2003 was primarily due to the incurrence of short-term debt in anticipation of the expected 2003 year-end closing of the acquisition of the McClain Plant, which was ultimately completed on July 9, 2004. In conjunction with the acquisition of the McClain Plant, the Company issued short-term debt to fund a portion of the acquisition, and, as a result, the short-term debt balance was approximately $216.1 million at July 31, 2004. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings. During October 2004, the Company issued approximately $170.0 million in commercial paper related to the redemption of the trust preferred securities, of which approximately $100.0 million was refinanced in November 2004 by the issuance of long-term debt.

The balance of Accounts Payable was approximately $476.2 million and $280.2 million at December 31, 2004 and 2003, respectively, an increase of approximately $196.0 million or 70.0 percent. The increase was primarily due to higher natural gas prices and volumes associated with Enogex s activities in the fourth quarter of 2004.

The balance of current Price Risk Management liabilities was approximately $102.9 million and $46.9 million at December 31, 2004 and 2003, respectively, an increase of approximately $56.0 million. The increase was primarily due to an increase in park and loan transactions, natural gas storage injections and withdrawals and related financial contracts associated with OERI s activities during 2004.

The balance of Long-Term Debt was approximately $1.42 billion and $1.44 billion at December 31, 2004 and 2003, respectively, a decrease of approximately $20 million or 1.4 percent. The decrease was primarily due to long-term debt maturities and the early retirement of long-term debt during 2004. These decreases were partially offset by the issuance of $140.0 million of long-term debt in August 2004 by OG&E to replace the short-term borrowings initially issued to finance the McClain Plant acquisition in addition to the issuance of $100.0 million of long-term debt in November 2004 related to the redemption of the trust preferred securities in October 2004.

The balance of Accrued Pension and Benefit Obligations was approximately $197.0 million and $167.4 million at December 31, 2004 and 2003, respectively, an increase of approximately $29.6

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million or 17.7 percent. The increase was primarily due to an increase in the liability associated with the Company s pension plan due to a decrease in the assumed discount rate. See Note 15 of Notes to Consolidated Financial Statements for a further discussion.

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

Heat Pump Loans

Prior to January 1, 2004, OG&E had a heat pump loan program that allowed qualifying customers to obtain a loan from OG&E to purchase a heat pump. In October 1998, OG&E sold approximately $25.0 million of its heat pump loans in a securitization transaction through OGE Consumer Loan LLC. During the second quarter of 2004, OG&E repurchased the outstanding heat pump loan balance of approximately $0.1 million. OG&E recorded a gain of approximately $0.6 million in the third quarter of 2004 related to this transaction. Effective November 19, 2004, the Company dissolved OGE Consumer Loan LLC. In November 1999, OG&E sold approximately $12.7 million of its heat pump loans in a securitization transaction through OGE Consumer Loan II LLC. In October 2004, OG&E repurchased the outstanding heat pump loan balance of approximately $1.1 million. OG&E recorded a loss of less than $0.1 million in the fourth quarter of 2004 related to this transaction. Effective January 31, 2005, the Company dissolved OGE Consumer Loan II LLC. Effective January 1, 2004, OG&E discontinued issuing heat pump loans to customers and all new heat pump loans are now processed and managed by a third party. OG&E continues to service the heat pump loans it recently repurchased in 2004 in addition to the heat pump loans OG&E sold during 2003. The finance rate on the heat pump loans was based upon market rates and was reviewed and updated periodically. The interest rate was 11.55 percent at December 31, 2003. OG&E s heat pump loan balance was approximately $1.3 million and $1.4 million at December 31, 2004 and 2003, respectively and is included in Accounts Receivable, Net in the Consolidated Balance Sheets.

OG&E sold approximately $8.5 million of its heat pump loans in December 2002 as part of a securitization transaction through OGE Consumer Loan 2002, LLC. The following table contains information related to this securitization.

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	2002
Date heat pump loans sold	December 2002
Total amount of heat pump loans sold (in millions)	$ 8.5
Heat pump loan balance at December 31, 2004 (in millions)	$ 3.9

Note interest rate		5.25%
Base servicing fee rate (paid monthly)		0.375%
Trustee/custodian fees (paid quarterly) (in whole dollars)	$	1,250
Owner trustee fees (paid annually) (in whole dollars)	$	4,000
Sole director s fee (paid quarterly) (in whole dollars)	$	1,125
Loss exposure by securitization issue (in millions)	$	0.6

Energy Insurance Bermuda Ltd. Mutual Business Program No. 19

Energy Insurance Bermuda Ltd. (EIB) is incorporated in Bermuda under the Companies Act of 1981, as amended. The Company began participating in EIB through Mutual Business Program No. 19 (MBP 19) on November 15, 1998. The Company is the sole participant in MBP 19. In August 2002, the Company issued a $5.0 million standby letter of credit to MBP 19 for the benefit of insuring parts of the Company s property and liability insurance programs. In June 2003, the standby letter of credit was increased to $8.0 million. MBP 19 was established to provide $15.0 million worth of property and liability insurance for the Company. The letter of credit was issued to provide protection for MBP 19 in the event of large insurance claim losses. At December 31, 2003, there were no drawings against this letter of credit. Because a letter of credit was issued, the total equity investment at risk of MBP 19 was not deemed sufficient to permit it to finance its activities without additional subordinated financial support from other parties. Therefore, MBP 19 was considered a variable interest entity (VIE) as defined in Interpretation No. 46 and the Company was the primary beneficiary which resulted in the consolidation of MBP 19 into the Company s Consolidated Financial Statements for the year ended December 31, 2003. Effective January 1, 2004, the reinsurer of the MBP 19 program agreed to remove the guarantee requirement which enabled the Company to terminate the standby letter of credit previously provided. However, the reinsurer added a ratings trigger requirement in the revised agreement such that if the commercial paper rating of the Company is lowered by two grades, MBP 19 may be surcharged an additional premium, which may result in an additional premium to the Company. Because the guarantee requirement was removed, the total equity investment at risk of MBP 19 was deemed sufficient to permit it to finance its activities without additional subordinated financial support from other parties. Therefore, effective January 1, 2004, MBP 19 was not considered a VIE as defined in Interpretation No. 46 which resulted in the deconsolidation of MBP 19 during the first quarter of 2004. The Company plans to terminate the MBP 19 program during the first quarter of 2005 and does not expect the impact of terminating this program to have a material effect on the Company s consolidated financial position or results of operations.

OG&E Railcar Leases

At December 31, 2004, OG&E has a noncancellable operating lease which has 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. At the end of the lease term which is March 31, 2006, OG&E has the option to purchase the railcars at a stipulated fair market value. If OG&E chose not to purchase the railcars and the actual value of the railcars was less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of approximately $36

million. OG&E expects to enter into a new lease agreement for railcars effective April 1, 2006, which should negate any financial exposure under the current lease agreement. 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.

Liquidity and Capital Requirements

The Company s primary needs for capital are related to replacing or expanding existing facilities in OG&E s electric utility business and replacing or expanding existing facilities (including technology) at Enogex. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage and delays in recovering unconditional fuel purchase obligations. 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)	$ 647.7	$ 235.7	$ 412.0	N/A	N/A
Enogex capital expenditures and acquisitions	77.5	32.2	45.3	N/A	N/A
Other Operations capital expenditures	36.1	12.1	24.0	N/A	N/A

Total capital expenditures	761.3	280.0	481.3	N/A	N/A
Maturities of long-term debt	1,460.4	146.1	6.6	$ 4.6	$ 1,303.1
Interest payments on long-term debt	1,042.2	79.2	144.4	143.4	675.2
Pension funding obligations	123.8	37.4	61.3	25.1	N/A
Total capital requirements	3,387.7	542.7	693.6	173.1	1,978.3
Operating lease obligations					
OG&E railcars	51.7	5.4	10.7	10.7	24.9
Enogex noncancellable operating leases	8.1	3.7	4.1	0.2	0.1
Total operating lease obligations	59.8	9.1	14.8	10.9	25.0
Other purchase obligations and commitments					
OG&E cogeneration capacity payments	465.6	99.5	194.2	171.9	N/A
OG&E fuel minimum purchase commitments	907.0	170.8	319.0	251.7	165.5
Other	75.7	7.4	14.9	14.9	38.5
Total other purchase obligations and commitments	1,488.3	277.7	528.1	438.5	204.0
Total capital requirements, operating lease obligations and other purchase obligations and commitments	4,895.8	829.5	1,236.5	622.5	2,207.3
Amounts recoverable through automatic fuel adjustment clause (B)	(1,424.3)	(275.7)	(523.9)	(434.3)	(190.4)
Total, net	$ 3,471.5	$ 553.8	$ 712.6	$ 188.2	$ 2,016.9

(A) Under current environmental laws and regulations, OG&E may be required to spend additional capital expenditures on its coal-fired plants. These expenditures would not begin until the year 2008. The amounts and timing of these expenditures is uncertain at the present time.
(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

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Variances in the actual cost of fuel used in electric generation (which includes the operating lease obligations for OG&E s railcar leases shown above) and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E s customers through 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. OG&E currently has pending before the OCC an application to recover the costs of gas transportation and storage services provided to it by Enogex pursuant to the contract between OG&E and Enogex. An adverse decision by the OCC could result in OG&E having to refund previously collected amounts. See Note 18 of Notes to Consolidated Financial Statements for a further discussion.

2004 Capital Requirements and Financing Activities

Total capital requirements, consisting of capital expenditures, maturities and retirements of long-term debt, interest payments on long-term debt and pension funding obligations, were approximately $840.0 million and contractual obligations, net of recoveries through automatic fuel adjustment clauses, were approximately $4.3 million resulting in total net capital requirements and contractual obligations of approximately $844.3 million in 2004. Approximately $7.8 million of the 2004 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $335.0 million and net contractual obligations of approximately $6.4 million totaling approximately $341.4 million in 2003, of which approximately $6.4 million was to comply with environmental regulations. During 2004, 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), issuance of long-term debt, proceeds from the sale of assets and the issuance of common stock pursuant to the Company s DRIP/DSPP. 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 for 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.

Early Retirement of Long-Term Debt

In 1998, Enogex issued a note in the amount of approximately $5.7 million payable to an unaffiliated former partial interest owner of NOARK. The note had a maturity date of July 1, 2020 and an interest rate of 7.00 percent. Principal and interest payments of approximately $0.8 million were due annually beginning July 1, 2004. In July 2004, Enogex made the initial $0.8 million payment and also made a payment of approximately $7.8 million, which included accrued interest since inception of the note, to repay the outstanding note balance and satisfy its remaining obligations related to this note. Enogex recorded a pre-tax gain of approximately $0.1 million in the third quarter of 2004 related to this transaction.

Asset Sales

Also contributing to the liquidity of the Company have been numerous asset sales by the Company. Since January 1, 2002, significant completed sales transactions have generated net sales

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proceeds of approximately $116.1 million. Sales proceeds generated to date have been used to reduce debt at Enogex and commercial paper at the holding company.

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

Issuance of Long-Term Debt

In August 2004, OG&E issued $140.0 million of long-term debt. The proceeds were used to replace a portion of the short-term borrowings initially used to fund a portion of the McClain Plant acquisition in July 2004. This debt has a maturity date of August 1, 2034 and an interest rate of 6.50 percent.

In September 2004, the Company filed a Form S-3 Registration Statement registering the sale of up to $200.0 million of the Company s unsecured debt securities. In November 2004, the Company issued $100.0 million of long-term debt, the proceeds of which were used to replace a portion of the short-term debt incurred to fund the redemption of the trust preferred securities on October 15, 2004. This new debt has a maturity date of November 15, 2014 and an interest rate of 5.00 percent.

Long-term Debt Maturities

During 2004 and 2003, approximately $51.0 million and $19.0 million, respectively, of Enogex s long-term debt matured and approximately $10.3 million and $12.0 million, respectively, was redeemed during 2004 and 2003 which is itemized in the following table.

(In millions)	**2004**	2003
Series Due 2003 -- 6.60% - 8.28%	**$ ---**	$ 19.0
Series Due 2004 -- 6.71% - 8.34%	**51.0**	---
Series Due 2018 -- 7.15%	**2.0**	2.0
Series Due 2020 -- 7.00%	**8.3**	---
Series Due 2023 -- 7.75%	**---**	10.0
Total	**$ 61.3**	$ 31.0

Maturities of the Company s long-term debt during the next five years consist of $146.1 million in 2005; $1.8 million in 2006; $4.8 million in 2007; $2.8 million in 2008 and $1.8 million in 2009. For OG&E, $110.0 million of long-term debt matures in 2005; however, in the Consolidated Statement of Capitalization at December 31, 2004, no amount is shown as Long-Term Debt Due Within One Year. The Company plans to refinance this amount and the Company believes they have the ability to do so as the Company and OG&E entered into new five-year revolving credit agreements in October 2004 in an amount up to $550 million which could be utilized to temporarily finance these notes when they mature in October 2005.

Interest Rate Swap Agreements

Fair Value Hedges

At December 31, 2004 and 2003, the Company had three outstanding interest rate swap agreements that qualified as fair value hedges: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate (LIBOR) and (ii)

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Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert a total of $200.0 million ($100.0 million for each interest rate swap agreement) of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR in arrears. The objective of these 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. These interest rate swaps qualified as fair value hedges under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At December 31, 2004 and 2003, the fair values pursuant to the interest rate swaps were approximately $7.9 million and $7.6 million, respectively, and the hedges were classified as Deferred Charges and Other Assets Price Risk Management in the Consolidated Balance Sheets. A corresponding net increase of approximately $7.9 million and $7.6 million was reflected in Long-Term Debt at December 31, 2004 and 2003, respectively, as these fair value hedges were effective at December 31, 2004 and 2003.

Cash Flow Hedges

The Company entered into four separate interest rate swap agreements, effective April 16, 2004, April 21, 2004, May 17, 2004 and July 16, 2004, respectively, to hedge approximately $20.0 million, $30.0 million, $20.0 million and $10.0 million, respectively, of future interest payments of long-term debt that was issued in November 2004. These interest rate swap agreements originally matured on October 15, 2004 but the maturity date was extended to November 8, 2004. The Company terminated these cash flow hedges on November 9, 2004, at which time approximately $4.0 million was recorded in other comprehensive income. This amount will be amortized to interest expense over the life of the related long-term debt.

Trust Originated Preferred Securities

On October 21, 1999, OGE Energy Capital Trust I, a wholly-owned financing trust of the Company, issued $200.0 million principal amount of 8.375 percent trust preferred securities with a maturity date of October 15, 2039. On October 15, 2004, the Company caused all of the outstanding trust preferred securities to be redeemed at $25 per share (100 percent of liquidation value). The redemption was initially funded with cash on hand and approximately $170.0 million in commercial paper. The Company refinanced a portion of this short-term debt with $100.0 million of long-term debt issued in November 2004. In October 2004, the Company wrote off approximately $5.9 million related to unamortized debt issuance costs for the trust preferred securities.

Future Capital Requirements

Capital Expenditures

The Company s current 2005 to 2007 construction program includes continued investment in system and transmission upgrades that is part of the Company s Customer Savings and Reliability Plan. OG&E has approximately 430 MWs of QF contracts that will expire at the end of 2007, unless extended by OG&E. In addition, effective September 1, 2004, OG&E entered into a new 15-year power sales agreement for 120 MWs with PowerSmith. OG&E will continue reviewing all of the supply alternatives to these expiring 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-

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determined rates. Accordingly, OG&E will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, OG&E will also assess the feasibility of constructing additional base load coal-fired units. See Note 18 of Notes to Consolidated Financial Statements for a description of the new PowerSmith QF contract.

To reliably meet the increased electricity needs of OG&E s customers during the foreseeable future, OG&E will continue to invest to maintain the integrity of the delivery system. Approximately $7.0 million of the Company s capital expenditures budgeted for 2005 are to comply with environmental laws and regulations.

Pension and Postretirement Benefit Plans

During 2004, actual asset returns for the Company s defined benefit pension plan were positively affected by growth in the equity markets; however, the growth in 2004 was not as strong as the growth in the equity markets in 2003. Approximately 62 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 2004, asset returns on the pension plan were approximately 12.51 percent as compared to approximately 22.76 percent in 2003. During the same time, 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 $50.0 million in 2003 to approximately $69.0 million in 2004. This increase was necessitated by the lower investment returns on assets and lower discount rates used to value the accumulated pension benefit obligations. During 2005, the Company plans to contribute approximately $37.4 million to the pension plan. 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.

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.

During 2004 and 2003, the Company made contributions to the pension plan and the restoration of retirement income plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2004 and 2003 of approximately $92.0 million and $55.7 million, respectively. At December 31, 2004 and 2003, the Company s projected pension benefit obligation exceeded the fair value of the pension plan assets and the restoration of retirement income plan assets by approximately $123.3 million and $131.8 million, respectively. 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, Employers Accounting for Pensions, required the recognition of an additional minimum liability in the amount of approximately $156.6 million and $137.6 million, respectively, at December 31, 2004 and 2003. 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

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2004 or 2003 and did not require a usage of cash and is therefore excluded from the Consolidated Statements 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.

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	P-2	A-2	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, 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, proceeds from the sales of common stock pursuant to the Company s DRIP/DSPP and long and short-term debt will be adequate over the next three years to meet anticipated capital expenditures, operating needs, payment of dividends and maturities of long-term debt. As discussed below, 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

The following table shows the Company s lines of credit in place and available cash at January 31, 2005. At January 31, 2005, the Company s short-term borrowings consisted of commercial paper.

Lines of Credit and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding	Maturity
OGE Energy Corp.	$ 15.0	$ ---	April 6, 2004
OG&E	100.0	---	October 20, 2009 (B)
OGE Energy Corp. (A)	450.0	---	October 20, 2009 (B)
	565.0	---	
Cash	14.9	N/A	N/A
Total	$ 579.9	$ ---	

(A) These lines of credit are used to back up a maximum of $300.0 million of the Company s commercial paper borrowings, which were approximately $187.6 million at January 31, 2005.
(B) Each of the new credit facilities has a five-year term with two options to extend the term for one year.

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On October 20, 2004, the Company and OG&E entered into revolving credit agreements totaling $550 million. These agreements include two separate credit facilities, one for the Company in an amount up to $450 million and one for OG&E in an amount up to $100 million. Each of the new credit facilities has a five-year term with two options to extend the term for one year. Planned uses of the revolving credit include working capital needs, back-up for the Company s commercial paper program, the issuance of letters of credit and for general corporate purposes.

The Company s and OG&E s ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade. Their respective back-up lines of credit contain rating grids that require annual fees and borrowing rates to increase if they suffer an adverse ratings impact. 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 $400 million in short-term borrowings at any one time. In November 2004, OG&E received approval from the FERC to incur up to $400 million in short-term borrowings for an additional two-year period beginning January 1, 2005 through December 31, 2006.

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, accrued removal obligations, regulatory assets and liabilities, unbilled revenue for OG&E, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and natural gas storage inventory and fair value and cash flow hedging policies. 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 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

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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 increases in discount rates will reduce funding requirements to the plan. The following table indicates the sensitivity of the pension plans funded status to these variables.

	Change	Impact on Funded Status
Actual plan asset returns	+/- 5 percent	+/- $18.1 million
Discount rate	+/- 0.25 percent	+/- $18.6 million
Contributions	+ $10.0 million	+ $10.0 million
Expected long-term return on plan assets	+/- 1 percent	None

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 determined or included in the 2005 earnings guidance.

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with 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.

In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. The scope of SFAS No. 143 includes the Company s accrued plant removal costs for generation, transmission, distribution, processing and pipeline assets. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of the fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of the fair value can be made. In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to remove certain assets associated with their retirements. As the Company currently has no plans to retire any of these assets (except as discussed

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below) and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will monitor these assets and record a liability when a reasonable estimate of the fair value can be made. During the third quarter of 2004, OG&E determined the definite life of a legal obligation within the scope of SFAS No. 143 to retire certain assets related to the expiration of a power supply contract in

June 2006. OG&E recorded an asset retirement obligation of approximately $1.1 million at September 30, 2004 and began amortizing this amount for 21 months beginning October 1, 2004.

The Company expects that the FASB will issue an interpretation related to SFAS No. 143 during the first quarter of 2005 in which an entity would be required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event if the liability s fair value can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation would be recognized when incurred. Uncertainty surrounding the timing and method of settlement that may be conditional on events occurring in the future would be factored into the measurement of the liability rather than the recognition of the liability. However, in some cases, there is insufficient information to estimate the fair value of an asset retirement obligation. In these cases, the liability would be initially recognized in the period in which sufficient information is available for an entity to make a reasonable estimate of the liability s fair value. The Company expects that this interpretation will be effective no later than the end of fiscal years ending after December 15, 2005. Additionally, the interpretation is expected to permit, but not require, restatement of interim financial information during any period of adoption. The FASB also has indicated that it will require both recognition of a cumulative change in accounting principle and disclosure of the liability on a pro forma basis for transition purposes. The Company will evaluate the financial impact when a final interpretation is issued.

OG&E and Enogex engage in cash flow and fair value hedge transactions to manage commodity risk and modify the rate composition of the debt portfolio. 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 hedging requirements and are executed based upon management established price targets. During 2003, OERI also utilized fair value hedges under SFAS No. 133 to manage commodity price exposure for natural gas storage inventory. However, during 2004, OERI decided not to utilize hedge accounting under SFAS No. 133 for natural gas storage inventory. 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 have entered into interest rate swap agreements on the debt portfolio to modify the interest rate exposure on fixed rate debt issues. These interest rate swaps qualify as fair value hedges under SFAS No. 133. The objective of these 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.

Electric Utility Segment

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. Excluding recoverable take or pay gas charges, the McClain Plant operating and maintenance expenses, depreciation, ad valorem taxes and interest on debt, regulatory assets are being amortized and reflected in rates charged to customers over periods of up to 20 years.

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.

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, 2004, 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 $0.5 million. At December 31, 2004 and 2003, Accrued Unbilled Revenues were approximately $45.5 million and $38.0 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Customer balances are generally written off if not collected within six months after the original due 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, 2004, 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 on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was approximately $2.7 million and $2.6 million at December 31, 2004 and 2003, respectively.

Natural Gas Pipeline Segment

Operating revenues for transportation, storage, gathering and processing services for Enogex are estimated each month based on the prior month s activity, 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 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.

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 a model to estimate the fair value of its energy contracts including derivatives that do not have an independent market price. At December 31, 2004, unrealized mark-to-market gains were approximately $20.7 million, which included approximately $0.4 million of unrealized mark-to-market gains that were calculated utilizing models. At December 31, 2004, a price movement of one percent for prices verified by independent parties would result in changes in unrealized mark-to-market gains of approximately $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 and liabilities on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income. See Note 2 of Notes to Consolidated Financial Statements for a further discussion of accounting for energy contracts.

Effective January 1, 2003, natural gas storage inventory used in OERI s business activities are accounted for at the lower of cost or market in accordance with the guidance in EITF 02-3 which resulted in the rescission of EITF Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, as amended. Prior to January 1, 2003, this inventory was accounted for on a fair value accounting basis utilizing a gas index that in management s opinion approximated the current market value of natural gas in that region as of the Balance Sheet date. On April 1, 2003, natural gas storage inventory used in OERI s business activities began to be accounted for under SFAS No. 133. In order to minimize risk, OERI enters into contracts or hedging instruments to hedge the fair value of this inventory. For any contracts that qualify for hedge accounting under SFAS No. 133, the hedged portion of the inventory is recorded at fair value with an offsetting gain or loss recorded currently in earnings. During 2003, OERI utilized hedge accounting under SFAS No. 133 for natural gas storage inventory; however, during 2004, OERI decided not to utilize hedge accounting under SFAS No. 133 for natural gas storage inventory. Ineffectiveness associated with OERI s fair value hedge strategy was not material. The fair value of the hedging instrument is also recorded on the books of OERI as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. As part of its recurring business activity, OERI injects and withdraws natural gas under the terms of storage capacity contracts; the amount of natural gas inventory was approximately $29.0 million and $82.4 million at December 31, 2004 and 2003, respectively. See Note 2 of Notes to Consolidated Financial Statements for a further discussion. 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.

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 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 $1.8 million and $1.6 million at December 31, 2004 and 2003, respectively.

Accounting Pronouncements

See Note 2 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 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 California in its 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. OG&E currently has one important matter pending before the OCC. See Note 18 of Notes of Consolidated Financial Statements for a further discussion.

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. Management consults with 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. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently 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. This assessment of currently pending or threatened lawsuits is subject to change. See Note 17 of Notes to Consolidated Financial Statements for a discussion of the Company s commitments and contingencies.

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Quantitative and Qualitative Disclosures About Market Risk.

Risk Management

The risk management process established by the Company is designed to measure both quantitative and qualitative risks in its businesses. A corporate risk management department, under the direction of a corporate risk oversight committee, has been established to review these risks on a regular basis. The Company is exposed to market risk in its normal course of business, including changes in certain commodity prices and interest rates. The Company also engages in price risk management activities for both trading and non-trading purposes.

To manage the volatility relating to these exposures, the Company enters into various derivative and other forward transactions pursuant to the Company s policies on hedging practices. These positions are monitored using techniques such as mark-to-market valuation, value-at-risk and sensitivity analysis.

Interest Rate Risk

The Company s exposure to changes in interest rates relates primarily to long-term debt obligations 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 rate 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.

Fair Value Hedges

At December 31, 2004 and 2003, the Company had three outstanding interest rate swap agreements that qualified as fair value hedges: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month LIBOR and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert a total of $200.0 million ($100.0 million for each interest rate swap agreement) of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR in arrears. The objective of these 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. These interest rate swaps qualified as fair value hedges under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At December 31, 2004 and 2003, the fair values pursuant to the interest rate swaps were approximately $7.9 million and $7.6 million, respectively, and the hedges were classified as Deferred Charges and Other Assets Price Risk Management in the Consolidated Balance Sheets. A corresponding net increase of approximately $7.9 million and $7.6 million was reflected in Long-Term Debt at December 31, 2004 and 2003, respectively, as these fair value hedges were effective at December 31, 2004 and 2003.

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Cash Flow Hedges

The Company entered into four separate interest rate swap agreements, effective April 16, 2004, April 21, 2004, May 17, 2004 and July 16, 2004, respectively, to hedge approximately $20.0 million, $30.0 million, $20.0 million and $10.0 million, respectively, of future interest payments of long-term debt that was issued in November 2004. These interest rate swap agreements originally matured on October 15, 2004 but the maturity date was extended to November 8, 2004. The Company terminated these cash flow hedges on November 9, 2004, at which time approximately $4.0 million was recorded in other comprehensive income. This amount will be amortized to interest expense over the life of the related long-term debt.

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. The valuation of the Company s interest rate swaps was determined primarily based on quoted market prices. The following table shows the Company s long-term debt maturities and the weighted-average interest rates by maturity date.

(Dollars in millions)	2005	2006	2007	2008	2009	Thereafter	Total	12/31/04 Fair Value
Fixed rate debt								
Principal amount	$ 146.1	$ 1.8	$ 4.8	$ 2.8	$ 1.8	$ 845.5	$ 1,002.8	$ 1,097.6
Weighted-average interest rate	7.07%	7.15%	7.83%	7.12%	7.15%	6.77%	6.82%	---
Variable rate debt								
Principal amount (A)	---	---	---	---	---	$ 457.6	$ 457.6	$ 458.2
Weighted-average interest rate	---	---	---	---	---	3.45%	3.45%	---

(A) Amount includes an increase to the fair value of long-term debt of approximately $7.9 million due to the Company s interest rate swaps.

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.

The trading activities are conducted throughout the year subject to daily and monthly trading stop loss limits of $2.5 million. The daily loss exposure from trading activities is measured primarily using value at risk, subject to a $1.5 million limit, as well as other quantitative risk measurement techniques. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company s operating income.

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 operating income received by the Company as compensation for operating some of its assets. To partially reduce non-trading commodity price risk incurred in the Company s normal

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course of business caused by these market fluctuations, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the operating income received by the Company as compensation for operating these assets. 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.

Sensitivity analyses have been prepared to estimate the Company s exposure to the market risk of the Company s natural gas and natural gas liquids commodity positions. These analyses are done for both trading and 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. 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. Because quoted market prices are not available for all of the Company s non-trading positions, 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 results of these analyses, which may differ from actual results, are as follows for 2004.

(In millions)	Trading	Non-Trading
Commodity market risk, net	$ 0.3	$ 7.8

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Financial Statements and Supplementary Data.

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2004**	2003
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 26.4**	$ 245.6
Accounts receivable, net	**487.9**	350.2
Accrued unbilled revenues	**45.5**	38.0
Fuel inventories	**89.0**	149.6
Materials and supplies, at average cost	**53.2**	45.1
Price risk management	**118.6**	61.3
Gas imbalances	**100.1**	70.0
Accumulated deferred tax assets	**13.7**	9.4
Fuel clause under recoveries	**54.3**	4.0
Recoverable take or pay gas charges	**17.0**	---
Other	**13.5**	21.5
Total current assets	**1,019.2**	994.7
OTHER PROPERTY AND INVESTMENTS, at cost	**31.4**	34.7
PROPERTY, PLANT AND EQUIPMENT		
In service	**5,957.6**	5,610.0
Construction work in progress	**110.5**	56.7
Other	**5.8**	15.0
Total property, plant and equipment	**6,073.9**	5,681.7
Less accumulated depreciation	**2,492.9**	2,358.5
Net property, plant and equipment	**3,581.0**	3,323.2
DEFERRED CHARGES AND OTHER ASSETS		
Recoverable take or pay gas charges	**---**	32.5
Income taxes recoverable from customers, net	**30.9**	31.6
Intangible asset - unamortized prior service cost	**38.0**	40.2
Prepaid benefit obligation	**92.7**	55.7
Price risk management	**19.6**	13.5

Other	**57.5**	58.6
Total deferred charges and other assets	**238.7**	232.1
TOTAL ASSETS	**$4,870.3**	$4,584.7

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

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OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2004**	2003
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 125.0**	$ 202.5
Accounts payable	**476.2**	280.2
Dividends payable	**29.9**	29.1
Customers deposits	**48.3**	41.6
Accrued taxes	**14.1**	18.7
Accrued interest	**33.2**	30.7
Accrued interest - unconsolidated affiliate	**---**	3.5
Tax collections payable	**7.2**	7.9
Accrued vacation	**17.9**	17.2
Long-term debt due within one year	**35.1**	52.1
Non-recourse debt of joint venture	**1.2**	1.2
Price risk management	**102.9**	46.9
Gas imbalances	**22.8**	22.5
Fuel clause over recoveries	**---**	32.4
Provision for payments of take or pay gas	**21.0**	---
Other	**40.6**	41.2
Total current liabilities	**975.4**	827.7
LONG-TERM DEBT		
Long-term debt	**1,385.1**	1,189.7
Non-recourse debt of joint venture	**39.0**	40.2
Long-term debt - unconsolidated affiliate	**---**	206.2
Total long-term debt	**1,424.1**	1,436.1
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**197.0**	167.4
Accumulated deferred income taxes	**802.0**	747.3
Accumulated deferred investment tax credits	**36.8**	42.0
Accrued removal obligations, net	**122.2**	116.3
Price risk management	**6.6**	4.5
Provision for payments of take or pay gas	**---**	32.5
Asset retirement obligation	**1.1**	---
Other	**19.5**	9.3
Total deferred credits and other liabilities	**1,185.2**	1,119.3

STOCKHOLDERS EQUITY		
Common stockholders equity	**700.8**	636.1
Retained earnings	**659.8**	623.9
Accumulated other comprehensive loss, net of tax	**(75.0)**	(58.4)
Total stockholders equity	**1,285.6**	1,201.6
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$4,870.3**	$4,584.7

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

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OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*				**2004**	2003
STOCKHOLDERS EQUITY					
Common stock, par value $0.01 per share; authorized 125.0 shares; and outstanding 90.0 and 87.4 shares, respectively				**$ 0.9**	$ 0.9
Premium on capital stock				**699.9**	635.2
Retained earnings				**659.8**	623.9
Accumulated other comprehensive loss, net of tax				**(75.0)**	(58.4)
Total stockholders equity				**1,285.6**	1,201.6
LONG-TERM DEBT					
SERIES	DATE DUE				
Senior Notes-OGE Energy Corp.					
5.00 %	Senior Notes, Series Due November 15, 2014	**100.0**	---		
Unamortized discount		**(0.9)**	---		
Senior Notes-OG&E					
7.125 %	Senior Notes, Series Due October 15, 2005	**110.0**	110.0		
6.50 %	Senior Notes, Series Due July 15, 2017	**125.0**	125.0		
Variable %	Senior Notes, Series Due October 15, 2025	**114.0**	114.0		
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**	---		
Other bonds-OG&E					
Variable %	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0		
Variable %	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4		
Variable %	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0		
Unamortized discount		**(2.2)**	(2.2)		
Enogex Notes					
6.71% - 8.34%	Medium-Term Notes, Series Due 2004	**---**	51.0		
6.81% - 6.99%	Medium-Term Notes, Series Due 2005	**34.3**	34.2		
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	**200.0**	200.0		
Variable %	Medium-Term Notes, Series Due 2010	**208.8**	209.5		
7.15%	Medium-Term Notes, Series Due 2018	**67.0**	69.0		
7.00%	Medium-Term Notes, Series Due 2020	**---**	8.3		
Unconsolidated affiliate (Note 12)		**---**	206.2		

Total long-term debt	**1,460.4**	1,489.4
Less long-term debt due within one year	**35.1**	52.1
Non-recourse of joint venture	**1.2**	1.2
Total long-term debt (excluding long-term debt due within one year)	**1,424.1**	1,436.1
Total Capitalization	**$2,709.7**	$2,637.7

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

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(In millions, except per share data)*	**2004**	2003	2002
OPERATING REVENUES			
Electric Utility operating revenues	**$1,578.1**	$1,517.1	$1,388.0
Natural Gas Pipeline operating revenues	**3,348.5**	2,261.9	1,635.9
Total operating revenues	**4,926.6**	3,779.0	3,023.9
COST OF GOODS SOLD			
Electric Utility cost of goods sold	**865.0**	792.7	662.2
Natural Gas Pipeline cost of goods sold	**3,097.7**	2,053.3	1,458.1
Total cost of goods sold	**3,962.7**	2,846.0	2,120.3
Gross margin on revenues	**963.9**	933.0	903.6
Other operation and maintenance	**392.2**	371.7	370.0
Depreciation	**178.6**	176.9	182.5
Impairment of assets	**7.8**	10.2	50.1
Taxes other than income	**67.8**	67.3	65.3
OPERATING INCOME	**317.5**	306.9	235.7
OTHER INCOME (EXPENSE)			
Other income	**12.1**	8.1	3.7
Other expense	**(5.5)**	(9.0)	(4.7)
Net other income (expense)	**6.6**	(0.9)	(1.0)
INTEREST INCOME (EXPENSE)			
Interest income	**5.2**	1.3	1.7
Interest on long-term debt	**(74.4)**	(75.2)	(86.2)
Interest on trust preferred securities	**---**	---	(17.3)
Interest expense - unconsolidated affiliate	**(13.7)**	(17.3)	---
Allowance for borrowed funds used during construction	**1.7**	0.5	0.9
Interest on short-term debt and other interest charges	**(9.7)**	(6.0)	(8.2)
Net interest expense	**(90.9)**	(96.7)	(109.1)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**233.2**	209.3	125.6
INCOME TAX EXPENSE	**80.2**	73.7	44.6

INCOME FROM CONTINUING OPERATIONS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	**153.0**	135.6	81.0
DISCONTINUED OPERATIONS (NOTE 4)			
Income from discontinued operations	**0.8**	1.8	8.4
Income tax expense (benefit)	**0.3**	2.2	(1.4)
Income (loss) from discontinued operations	**0.5**	(0.4)	9.8
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	**153.5**	135.2	90.8
CUMULATIVE EFFECT ON PRIOR YEARS OF CHANGE IN ACCOUNTING PRINCIPLE, net of tax of $3.4	**---**	(5.4)	---
NET INCOME	**$ 153.5**	$ 129.8	$ 90.8
BASIC AVERAGE COMMON SHARES OUTSTANDING	**88.0**	81.8	78.1
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**88.5**	82.1	78.2
BASIC EARNINGS (LOSS) PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 1.73**	$ 1.66	$ 1.04
Income from discontinued operations, net of tax	**0.01**	---	0.12
Loss from cumulative effect of accounting change, net of tax	**---**	(0.07)	---
NET INCOME	**$ 1.74**	$ 1.59	$ 1.16
DILUTED EARNINGS (LOSS) PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 1.72**	$ 1.65	$ 1.04
Income from discontinued operations, net of tax	**0.01**	---	0.12
Loss from cumulative effect of accounting change, net of tax	**---**	(0.07)	---
NET INCOME	**$ 1.73**	$ 1.58	$ 1.16
DIVIDENDS DECLARED PER SHARE	**$ 1.33**	$ 1.33	$ 1.33

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)*	**2004**	2003	2002
BALANCE AT BEGINNING OF PERIOD	**$ 623.9**	$ 604.7	$ 617.9
ADD: Net income	**153.5**	129.8	90.8
Total	**777.4**	734.5	708.7
DEDUCT: Dividends declared on common stock	**117.6**	110.6	104.0

BALANCE AT END OF PERIOD	**$ 659.8**	$ 623.9	$ 604.7

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(In millions)*	**2004**	2003	2002
Net income	**$ 153.5**	$ 129.8	$ 90.8
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment [($21.2), $23.8 and ($85.5) pre-tax, respectively]	**(13.0)**	14.6	(52.4)
Reclassification adjustments - contract settlements [$0.2 pre-tax]	**---**	---	0.1
Deferred hedging gains (losses) [($1.1) and $1.5 pre-tax, respectively]	**(0.7)**	0.9	---
(Reversal of unrealized gain) unrealized gains on available-for-sale securities [($0.6) and $0.6 pre-tax, respectively]	**(0.4)**	0.4	---
Settlement of cash flow hedge [($4.0) pre-tax]	**(2.5)**	---	---
Total other comprehensive income (loss), net of tax	**(16.6)**	15.9	(52.3)
Total comprehensive income	**$ 136.9**	$ 145.7	$ 38.5

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

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OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 *(In millions)*	**2004**	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 153.5**	$ 129.8	$ 90.8
Adjustments to reconcile net income to net cash provided from operating activities			
(Income) loss from discontinued operations	**(0.5)**	0.4	(9.8)
Cumulative effect of change in accounting principle	**---**	5.4	---
Depreciation	**178.6**	176.9	182.5
Impairment of assets	**7.8**	10.2	50.1
Deferred income taxes and investment tax credits, net	**53.1**	116.3	33.1
Allowance for equity funds used during construction	**(0.9)**	---	---
Gain on sale of assets	**(6.5)**	(6.1)	(1.0)
Ineffectiveness of interest rate swap	**---**	---	0.2
Price risk management assets	**(63.1)**	(45.8)	4.8
Price risk management liabilities	**52.5**	36.7	16.4
Other assets	**(27.2)**	(6.7)	(36.8)
Other liabilities	**11.0**	0.8	(8.6)
Change in certain current assets and liabilities			
Accounts receivable, net	**(137.7)**	(45.6)	(83.5)
Accrued unbilled revenues	**(7.5)**	(9.8)	7.4

Fuel, materials and supplies inventories	**52.5**	(54.8)	(26.5)
Gas imbalances asset	**(30.1)**	(22.3)	(32.4)
Fuel clause under recoveries	**(50.3)**	10.7	(14.7)
Other current assets	**3.5**	(2.3)	(1.1)
Accounts payable	**196.0**	18.5	108.5
Customers deposits	**6.7**	1.0	12.1
Accrued taxes	**(4.6)**	(1.6)	(4.8)
Accrued interest	**(1.0)**	(1.4)	(4.2)
Fuel clause over recoveries	**(32.4)**	32.4	(23.4)
Gas imbalances liability	**0.3**	(0.3)	16.3
Other current liabilities	**5.8**	19.4	7.9
Net Cash Provided from Operating Activities	**359.5**	361.8	283.3
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(431.8)**	(181.3)	(234.5)
Proceeds from sale of assets	**9.3**	16.2	1.7
Other investing activities	**0.7**	1.6	(0.5)
Net Cash Used in Investing Activities	**(421.8)**	(163.5)	(233.3)
CASH FLOWS FROM FINANCING ACTIVITIES			
Retirement of long-term debt	**(267.4)**	(31.0)	(140.0)
(Decrease) increase in short-term debt, net	**(77.5)**	(72.5)	126.2
Proceeds from long-term debt	**237.0**	---	---
Premium on issuance of common stock	**62.5**	171.3	3.1
Distribution from (to) minority interest	**2.6**	(2.5)	---
Dividends paid on common stock	**(114.6)**	(98.6)	(99.5)
Net Cash Used in Financing Activities	**(157.4)**	(33.3)	(110.2)
DISCONTINUED OPERATIONS			
Net cash provided from (used in) operating activities	**0.5**	(1.9)	17.2
Net cash provided from investing activities	**---**	38.1	51.3
Net cash used in financing activities	---	---	(1.4)
Net Cash Provided from Discontinued Operations	**0.5**	36.2	67.1
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(219.2)**	201.2	6.9
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**245.6**	44.4	37.5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 26.4**	$ 245.6	$ 44.4

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 management of 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 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 and 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. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership (NOARK), Enogex also owns a controlling interest in and operates Ozark Gas Transmission, L.L.C. (Ozark), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex was previously engaged in the exploration and production of natural gas, however, this portion of Enogex s business, along with interests in certain gas gathering and processing assets in Texas, was sold in 2002 and in the first quarter of 2003 and are reported in the Consolidated Financial Statements as discontinued operations. During the third quarter of 2004, Enogex entered into a joint venture arrangement with a third party and contributed certain of its natural gas compression assets to use in the joint venture, whose primary business focus will be the rental of compression assets. Enogex created a wholly-owned limited liability company, Enogex Compression Company, LLC (Enogex Compression), to act as the participating entity in the joint venture. Enogex Compression holds a majority ownership in the joint venture and the third party acts as the manager and conducts the daily operations of the joint venture. Enogex Compression has been consolidated in the Company s financial statements with a minority interest recorded.

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 Distragas method. The Distragas method is a three-factor formula that uses an equal weighting of payroll, operating income

and assets. 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. Excluding recoverable take or pay gas charges, the McClain Plant operating and maintenance expenses, depreciation, ad valorem taxes and interest on debt in the table below, regulatory assets are being amortized and reflected in rates charged to customers over periods of up to 20 years.

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

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

(In millions)	**2004**	2003
Regulatory Assets		
Fuel clause under recoveries	**$ 54.3**	$ 4.0

Recoverable take or pay gas charges	**17.0**	32.5
Income taxes recoverable from customers, net	**30.9**	31.6
Unamortized loss on reacquired debt	**21.0**	22.1
McClain Plant expenses	**11.0**	---
January 2002 ice storm	**1.8**	3.6
Arkansas transition costs	**0.7**	---
Miscellaneous	**0.6**	0.4
Total Regulatory Assets	**$ 137.3**	$ 94.2
Regulatory Liabilities		
Accrued removal obligations, net	**$ 122.2**	$ 116.3
Estimated refund on gas transportation and storage case	**6.9**	---
Estimated refund on FERC fuel	**1.0**	1.0
Fuel clause over recoveries	**---**	32.4
Total Regulatory Liabilities	**$ 130.1**	$ 149.7

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

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impact of fuel price volatility on customers bills. As a result, OG&E 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. OG&E expects to recover the fuel clause under recoveries during 2005.

Recoverable take or pay gas charges represent OG&E s estimate of the maximum amount that it could be obligated to pay under certain take-or-pay contracts. OG&E believes that it is entitled to recover any such amounts from its customers through its regulatorily approved automatic fuel adjustment clauses or other regulatory mechanisms.

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.

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 recovered over the term of the long-term debt which replaced the previous long-term debt.

As a result of the acquisition of a 77 percent interest in the 520 megawatt (MW) NRG McClain Station (the McClain Plant) completed on July 9, 2004, and consistent with the 2002 agreed-upon settlement of OG&E s rate case (the Settlement Agreement) with the OCC, OG&E has 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. All prudently incurred costs accrued through the regulatory asset within the 12-month period would be included in OG&E s prospective cost of service and would be recovered over a period to be determined by the OCC.

On November 22, 2002, the OCC signed a rate order containing the provisions of a Settlement Agreement of OG&E s rate case. The Settlement Agreement provides for, among other things, 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 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 of 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. If any of the $5.4 million is not recovered at the end of the three years, the OCC will authorize the recovery of any remaining costs. During the year ended December 31, 2004, OG&E recovered approximately $1.8 million in annual net profits from off-system sales, gave 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.

In April 1999, Arkansas passed a law (the Restructuring Law) calling for restructuring of the electric utility industry at the retail level. The Restructuring Law, which had initially targeted customer choice of electricity providers by January 1, 2002, was repealed in March 2003 before it was implemented. As part of the repeal legislation, electric public utilities were permitted to recover transition costs. OG&E incurred approximately $2.4 million in transition costs necessary to carry out its responsibilities associated with efforts to implement retail open access. On January 20, 2004, the APSC issued an order which authorized OG&E to recover approximately $1.9 million in transition costs over an 18-month period beginning February 2004.

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.

On November 22, 2002, the OCC signed a rate order containing the provisions of the Settlement Agreement of OG&E s rate case. As part of the Settlement Agreement, OG&E 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 Settlement Agreement. The prescribed bidding process detailed in the Settlement Agreement provided that each generation facility seek bids separately for the services required. OG&E believes that in order for it to achieve maximum coal generation, deliver the lowest cost energy to its customers and ensure reliable electric service, it must have integrated, firm no-notice load following service for both gas transportation and gas storage. On April 29, 2003, as required by the Settlement Agreement, OG&E filed an application with the OCC in which 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. On October 22, 2004, the administrative law judge overseeing the proceeding recommended approximately $41.9 million annual demand fee recovery with OG&E refunding to its customers any demand fees collected in excess of this amount. If this recommendation is ultimately accepted, OG&E believes its refund obligation would be approximately $6.9 million at December 31, 2004, which the Company does not believe is material in light of previously established reserves. See Note 18 for a further discussion.

Management continuously monitors the future recoverability of regulatory assets. When in management s judgment future recovery becomes impaired, the amount of the regulatory asset is 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, accrued removal obligations, regulatory assets and liabilities, unbilled revenue for OG&E, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and natural gas storage inventory and fair value and cash flow hedging policies.

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 $33.9 million and $38.7 million at December 31, 2004 and 2003, 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 original due 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 $4.5 million and $4.2 million at December 31, 2004 and 2003, respectively.

For OG&E, new business customers are required to provide a security deposit in the form of a case, bond, or irrevocable letter of credit which is refunded when the account is closed. New residential customers, whose outside credit scores indicate risk, are required to provide a security deposit which is refunded after 12 months of good payment history per the regulatory rules. The payment behavior of all existing customers is monitored and if the payment behavior indicates sufficient risk per the regulatory rules, 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.

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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 $24.9 million for 2004 and 2003, respectively, based on the average cost of fuel purchased. The amount of fuel inventory was approximately $42.2 million and $60.0 million at December 31, 2004 and 2003, respectively.

Effective December 31, 2003, approximately $13.7 million of natural gas storage inventory that was previously classified as Fuel Inventories was reclassified to Property, Plant and Equipment on the Consolidated Balance Sheet due to the gas transportation and storage contract between OG&E and Enogex requiring a minimum volume of natural gas be kept in the Enogex system.

Enogex

Effective January 1, 2003, natural gas storage inventory used in OGE Energy Resources, Inc. s (OERI) business activities are accounted for at the lower of cost or market in accordance with the guidance in Emerging Issues Task Force (EITF) Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, which resulted in the rescission of EITF Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, as amended. Prior to January 1, 2003, OERI s inventory was accounted for on a fair value accounting basis utilizing a gas index that in management s opinion approximated the current market value of natural gas in that region as of the Balance Sheet date. On April 1, 2003, natural gas storage inventory used in OERI s business activities began to be accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. In order to minimize risk, OERI enters into contracts or hedging instruments to hedge the fair value of this inventory. For any contracts that qualify for hedge accounting under SFAS No. 133, the hedged portion of the inventory is recorded at fair value with an offsetting gain or loss recorded currently in earnings. Ineffectiveness associated with OERI s fair value hedge strategy was not material in 2003 or 2004. The fair value of the hedging instrument is also recorded on the books of OERI as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. During 2003, OERI utilized hedge accounting under SFAS No. 133 for natural gas storage inventory; however, during 2004, OERI decided not to utilize hedge accounting under SFAS No. 133 for natural gas storage inventory. As part of its recurring business activity, OERI injects and withdraws natural gas under the terms of storage capacity contracts; the amount of natural gas inventory was approximately $29.0 million and $82.4 million at December 31, 2004 and 2003, respectively. See Note 2 for a further discussion.

Effective December 31, 2003, approximately $20.8 million of natural gas storage inventory that was previously classified as Property, Plant and Equipment used in Enogex Inc. s business activities was reclassified to Fuel Inventories on the Consolidated Balance Sheet. During the fourth quarter of 2003, Enogex implemented a business process to actively manage seasonal opportunities around the four billion cubic feet previously reserved to manage pipeline system requirements during peak periods. The intent of management is to capture commercial opportunities while maintaining adequate inventory levels necessary to meet ongoing contractual obligations.

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Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by the Company 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. The Company values all imbalances at average market prices estimated to be in effect at the time the imbalance will be settled. Also, included in Gas Imbalances on the Consolidated Balance Sheets are planned or managed imbalances related to Enogex s marketing business, referred to as park and loan transactions. Park and loan assets were approximately $76.0 million and $45.4 million, respectively, at December 31, 2004 and 2003 and park and loan liabilities were approximately $2.4 million and $9.7 million, respectively, at December 31, 2004 and 2003. Operational imbalance assets were approximately $24.1 million and $24.6 million, respectively, at December 31, 2004 and 2003 and operational imbalance liabilities were approximately $20.4 million and $12.8 million, respectively, at December 31, 2004 and 2003.

Property, Plant and Equipment

OG&E

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at costs which include contracted services, direct labor, materials, overhead, transportation costs and the allowance for funds used during construction (AFUDC). Replacements of major units of property are capitalized as plant. The replaced plant is removed from plant balances and the cost of such property less salvage is charged to Accumulated Depreciation. Repair and replacement of minor items of property are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense. Effective January 1, 2003, removal expense has no longer been charged to Accumulated Depreciation but rather has been charged to regulatory liabilities in accordance with SFAS No. 143.

Enogex

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at costs which include contracted services, direct labor, materials and overheads used during construction. Replacements of units of property are capitalized as plant. For group assets, the replaced plant is removed from plant balances and charged to Accumulated Depreciation. For non-group assets, 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.

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The Company s property, plant and equipment are divided into the following major classes at December 31, 2004 and 2003, respectively.

December 31 *(In millions)*	**2004**	2003
OGE Energy Corp. (holding company)		
Property, plant and equipment	**$ 65.3**	$ 57.0
OGE Energy Corp. property, plant and equipment	**65.3**	57.0
OG&E		
Distribution assets	**1,934.0**	1,834.7
Electric generation assets	**1,828.3**	1,628.1
Transmission assets	**552.8**	536.9
Intangible plant	**6.3**	5.3
Other property and equipment	**313.0**	265.1
OG&E property, plant and equipment	**4,634.4**	4,270.1
Enogex		
Transportation and storage assets	**883.6**	879.9

Gathering and processing assets	**483.1**	467.4
Marketing assets	**7.5**	7.3
Enogex property, plant and equipment	**1,374.2**	1,354.6
Total property, plant and equipment	**$6,073.9**	$5,681.7

Depreciation

OG&E

The provision for depreciation, which was approximately 2.9 percent of the average depreciable utility plant for 2004 and 2003, 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.

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

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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 determined or included in the 2005 earnings guidance.

Allowance for Funds Used During Construction

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 4.99 percent, 1.67 percent and 2.40 percent for the years 2004, 2003 and 2002, respectively. The increase in the AFUDC rates in 2004 was primarily due to a portion of capital expenditures being funded by equity funds, which have a higher cost rate than short-term borrowings, which were used to fund capital expenditures in 2003 and 2002.

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 estimated each month based on the prior month s activity, 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 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

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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 and liabilities in the Consolidated Balance Sheets. See Note 2 for a further discussion.

The default processing fee, which decreases the volatility of Enogex s earnings stream by reducing Enogex s exposure to keep-whole processing arrangements, is implemented in the event the natural gas liquids revenue less the associated fuel and shrinkage costs is negative. The Company records any default processing fees billed to customers as deferred revenue until it becomes probable that the processing gross margin threshold in Enogex s Statement of Operating Conditions (SOC) will not be exceeded. Based on the 2004 processing gross margin, the default processing fees billed to customers in 2004 were recorded as deferred revenue as the 2004 processing gross margin exceeded the 2004 processing gross margin threshold in the SOC.

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. See Note 18 of Notes to Consolidated Financial Statements for a discussion of the proceeding before the OCC in which OG&E is seeking to recover costs billed to it by Enogex for gas transportation and storage services.

Stock-Based Compensation

Pursuant to the provisions of SFAS No. 123, Accounting for Stock-Based Compensation, the Company has elected to continue using the intrinsic value method of accounting for its stock-based employee compensation plans in accordance with Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. Accordingly, the Company has not recognized compensation expense for its stock-based awards to employees. See Note 10 for a further discussion related to the Company s Stock Incentive Plan. Also, see Note 2 for a discussion of a recent accounting pronouncement which replaces SFAS No. 123 that the Company will adopt effective July 1, 2005.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure an amendment of FASB Statement No. 123. SFAS No. 148 amended the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The following table reflects pro forma net income and income per average common share had the Company elected to adopt the fair value based method of SFAS No. 123:

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Year Ended December 31 *(In millions, except per share data)*	**2004**	2003	2002
Net income, as reported	**$ 153.5**	$ 129.8	$ 90.8
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	**1.0**	1.2	1.1
Pro forma net income	**$ 152.5**	$ 128.6	$ 89.7
Income per average common share			
Basic - as reported	**$ 1.74**	$ 1.59	$ 1.16
Basic - pro forma	**$ 1.73**	$ 1.57	$ 1.15
Diluted - as reported	**$ 1.73**	$ 1.58	$ 1.16
Diluted - pro forma	**$ 1.72**	$ 1.57	$ 1.15

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, 2004 and 2003 are as follows:

December 31 *(In millions)*	**2004**	2003
Minimum pension liability adjustment, net of tax	**$ (72.7)**	$ (59.7)
Deferred hedging gains, net of tax	**0.2**	0.9
Unrealized gains on available-for-sale securities, net of tax	**---**	0.4
Settlement of cash flow hedge, net of tax	**(2.5)**	---
Total accumulated other comprehensive loss, net of tax	**$ (75.0)**	$ (58.4)

Minimum Pension Liability Adjustment

Accumulated other comprehensive loss at both December 31, 2004 and 2003 included an after tax loss ($118.6 million pre-tax and $97.4 million pre-tax, respectively) 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, 2004.

Cash Flow Hedges

The Company entered into four separate interest rate swap agreements, effective April 16, 2004, April 21, 2004, May 17, 2004 and July 16, 2004, respectively, to hedge approximately $20.0

million, $30.0 million, $20.0 million and $10.0 million, respectively, of future interest payments of long-term debt that was issued in November 2004. These interest rate swap agreements originally matured on October 15, 2004 but the maturity date was extended to November 8, 2004. The Company terminated these cash flow hedges on November 9, 2004, at which time approximately $4.0 million was recorded in other comprehensive income. This amount will be amortized to interest expense over the life of the related long-term debt.

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. When a single estimate of the liability cannot be determined, the low end of the estimated range is recorded. 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 has been designated as one of several potentially responsible parties, the amount accrued represents OG&E s estimated share of the cost.

Reclassifications

Certain prior year amounts have been reclassified on the Consolidated Financial Statements to conform to the 2004 presentation.

2. Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. The scope of SFAS No. 143 includes the Company s accrued plant removal costs for generation, transmission, distribution, processing and pipeline assets. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of the fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of the fair value can be made. Asset retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations doctrine of promissory estoppel. The recognition of an asset retirement obligation is capitalized as part of the carrying amount of the long-lived asset. Asset retirement obligations represent future liabilities and, as a result, accretion expense is accrued on this liability until such time as the obligation is satisfied. In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to remove certain assets associated with their retirements. As the Company currently has no plans to retire any of these assets (except as discussed below) and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will

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arising under the monitor these assets and record a liability when a reasonable estimate of the fair value can be made. During the third quarter of 2004, OG&E determined the definite life of a legal obligation within the scope of SFAS No. 143 to retire certain assets related to the expiration of a power supply contract in June 2006. OG&E recorded an asset retirement obligation of approximately $1.1 million at September 30, 2004 and began amortizing this amount over 21 months beginning October 1, 2004.

The Company expects that the FASB will issue an interpretation related to SFAS No. 143 during the first quarter of 2005 in which an entity would be required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event if the liability s fair value can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation would be recognized when incurred. Uncertainty surrounding the timing and method of settlement that may be conditional on events occurring in the future would be factored into the measurement of the liability rather than the recognition of the liability. However, in some cases, there is insufficient information to estimate the fair value of an asset retirement obligation. In these cases, the liability would be initially recognized in the period in which sufficient information is available for an entity to make a reasonable estimate of the liability s fair value. The Company expects that this interpretation will be effective no later than the end of fiscal years ending after December 15, 2005. Additionally, the interpretation is expected to permit, but not require, restatement of interim financial information during any period of adoption. The FASB also has indicated that it will require both recognition of a cumulative change in accounting principle and disclosure of the liability on a pro forma basis for transition purposes. The Company will evaluate the financial impact when a final interpretation is issued.

In October 2002, the EITF reached a consensus on certain issues covered in EITF 02-3. One consensus of EITF 02-3 was to rescind EITF 98-10 effective for fiscal periods beginning after December 15, 2002. Effective October 25, 2002, all new contracts and physical inventories that would have been accounted for under EITF 98-10 were no longer marked to market through earnings unless the contracts met the definition of a derivative under SFAS No. 133. Application of the consensus for energy contracts and inventory that existed on or before October 25, 2002 that remain in effect at the date this consensus was initially applied were recognized as a cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, Accounting Changes. As a result, only energy contracts that meet the definition of a derivative in SFAS No. 133 are carried at fair value. The Company adopted this consensus effective January 1, 2003 resulting in a pre-tax loss of approximately $9.6 million ($5.9 million after tax). The loss, which was accounted for as a cumulative effect of a change in accounting principle during the first quarter of 2003, was primarily related to natural gas held in storage for trading purposes. This natural gas held in storage was sold during the first quarter of 2003 resulting in an increase in the gross margin on revenues (gross margin) in excess of the cumulative effect loss described above.

In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51. In October 2003, the FASB issued Interpretation No. 46-6, Effective Date of FASB Interpretation No. 46, Consolidation of Variable Interest Entities, in which the FASB agreed to defer, for public companies, the required effective dates to implement Interpretation No. 46 for interests held in a variable interest entity (VIE) or potential VIE that was created before February 1, 2003. The Company adopted this new interpretation effective December 31, 2003 resulting in a pre-tax gain of approximately $0.8 million ($0.5 million after tax). The adoption of this interpretation resulted in the deconsolidation of the trust originated preferred securities of OGE Energy Capital Trust I, a wholly-owned financing trust of the Company (see Note 12), and the consolidation of Energy Insurance Bermuda Ltd. Mutual

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Business Program No. 19 (MBP 19). Effective January 1, 2004, the reinsurer of the MBP 19 program agreed to remove the guarantee requirement which enabled the Company to terminate the standby letter of credit previously provided. However, the reinsurer added a ratings trigger requirement in the revised agreement such that if the commercial paper rating of the Company is lowered by two grades, MBP 19 may be surcharged an additional premium, which may result in an additional premium to the Company. Because the guarantee requirement was removed, the total equity investment at risk of MBP 19 was deemed sufficient to permit it to finance its activities without additional subordinated financial support from other parties. Therefore, effective January 1, 2004, MBP 19 was not considered a VIE as defined in Interpretation No. 46 which resulted in the deconsolidation of MBP 19 during the first quarter of 2004. The Company plans to terminate the MBP 19 program during the first quarter of 2005 and does not expect the impact of terminating this program to have a material effect on the Company s consolidated financial position or results of operations.

In November 2004, the FASB issued SFAS No. 151, Inventory Costs, an Amendment to ARB No. 43, Chapter 4. This statement amends the guidance in Accounting Research Bulletin No. 43, Chapter 4 Inventory Pricing , to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and spoilage. This statement requires these items to be recognized as current period charges regardless of whether the so abnormal criterion is met. Adoption of SFAS No. 151 is required for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company will adopt this new standard effective January 1, 2006. Management has not yet determined what the impact of this new standard will be on its consolidated financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123 (Revised), Share-Based Payment , which replaces SFAS No. 123 and supersedes APB Opinion No. 25. This statement applies to all share-based payment transactions in which an entity acquires goods or services by issuing (or offering to issue) its shares, share options or other equity instruments (except for equity instruments held by an employee share ownership plan) or by incurring liabilities to an employee or other supplier (a) in amounts based, at least in part, on the price of the entity s shares or other equity instruments or (b) that require or may require settlement by issuing the entity s equity shares or other equity instruments. This statement applies to all awards granted after the required effective date and to awards modified, repurchased or cancelled after that date. The cumulative effect of initially applying this statement, if any, is recognized as of the required effective date. This statement requires a public entity 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 (with limited exceptions). The grant-date fair value of employee share options and similar instruments will be estimated using option-pricing models adjusted for the unique characteristics of those instruments. If an equity award is modified after the grant date, incremental compensation cost will be recognized in an amount equal to the excess of the fair value of the modified award over the fair value of the original award immediately before the modification. As of the required effective date, all public entities that used the fair-value based method for either recognition or disclosure under SFAS No. 123 will apply this statement using a modified version of prospective application. Under that transition method, compensation cost is recognized on or after the required effective date for the portion of outstanding awards for which the requisite service has not yet been rendered, based on the grant-date fair value of those awards calculated under SFAS No. 123 for either recognition or pro forma disclosures. For periods prior to the required effective date, those entities may elect to apply a modified version of retrospective application under which financial statements for prior periods are adjusted on a basis consistent with the pro forma disclosures required for those periods

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by SFAS No. 123. Adoption of SFAS No. 123(R) is required for public entities as of the beginning of the first interim or annual period beginning after June 15, 2005. The Company will adopt this new standard effective July 1, 2005. Management has not yet determined what the impact of this new standard will be on its consolidated financial position or results of operations.

3. 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 2004 and 2003, the Company s use of non-trading price risk management instruments involved the use of commodity price and interest rate swap agreements. These agreements involve 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.

In accordance with SFAS No. 133, the Company recognizes all of its 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. 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 portion of a derivative s change in fair value is recognized currently in earnings. As a matter of policy, all hedged items and the derivatives used for cash flow hedges must be identical with respect to time and location and must be in compliance with SFAS No. 133. 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. Any amounts recorded in Accumulated Other Comprehensive Income will remain in other comprehensive income until such time as the forecasted transaction is deemed probable not to occur.

The Company s interest rate swap agreements include both fair value and cash flow hedges. The fair value hedges qualify for the shortcut method prescribed by SFAS No. 133. Under the shortcut method, the Company assumes that the hedged item s change in fair value is exactly as much as the derivative s change in fair value. 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. See Notes 1 and 13 for a description of the Company s interest rate swap agreements.

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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 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. 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.

4. Enogex Discontinued Operations

Enogex sold its interests in Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership (Belvan) for approximately $9.8 million in March 2002. The Company recognized an after tax gain of approximately $1.6 million related to the sale of these assets.

Enogex sold its exploration and production assets located in Oklahoma, Texas, Arkansas and Mississippi for approximately $15.0 million in August 2002. The Company recognized an after tax gain of approximately $2.3 million related to the sale of these assets.

Enogex sold its exploration and production assets located in Michigan for approximately $32.0 million in November 2002. The Company recognized an after tax gain of approximately $2.9 million related to the sale of these assets.

Enogex sold its interests in the NuStar Joint Venture (NuStar) for approximately $37.0 million in February 2003. The Company recognized an after tax gain of approximately $1.4 million related to the sale of these assets in the first quarter of 2003. Following completion of the final accounting for the NuStar sale, the Company recorded an additional charge of approximately $0.2 million after tax in the third quarter of 2003. The final accounting is subject to approval by all parties to the sale of the joint venture interest. During 2004, the Company recognized approximately $0.5 million after tax from funds received related to an overpayment for natural gas purchases in a prior period.

The Consolidated Financial Statements of the Company have been restated to reflect Enogex s exploration and production assets, NuStar and Belvan, all of which were part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of the exploration and production assets, NuStar and Belvan have been excluded from the respective captions in the Consolidated Financial Statements and have been reported as Income (loss) from Discontinued Operations and Net Cash Provided from Discontinued Operations. There were no outstanding balances related to the exploration and production assets, NuStar and Belvan on the Consolidated Balance Sheets. Summarized financial information for the discontinued operations as of December 31 is as follows:

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(In millions)	**2004**	2003	2002
Operating revenues from discontinued operations	**$ 0.8**	$ 7.8	$ 79.5
Income from discontinued operations before taxes	**0.8**	1.8	8.4

5. Asset Disposals

Ozark sold approximately 29 miles of transmission lines of its pipeline for approximately $10.0 million in January 2003. Ozark recognized a gain of approximately $5.3 million and approximately $1.1 million in minority interest expense in the first quarter of 2003 related to the sale of these assets, which is recorded in Other Income and Other Expense, respectively, in the Consolidated Statements of Income. These assets were part of the Natural Gas Pipeline segment.

During the second quarter of 2004, OG&E sold land and buildings near its principal executive offices for approximately $0.9 million. OG&E recognized a gain of approximately $0.3 million related to the sale of this asset, which is recorded in Other Income in the Consolidated Statements of Income. This asset was part of the Electric Utility segment.

In September 2004, OG&E sold its interests in its natural gas producing properties for approximately $3.1 million. These interests had a carrying value of approximately $0.1 million and OG&E recognized a gain of approximately $3.0 million, which is recorded in Other Income in the Consolidated Statements of Income. In December 2004, OG&E recognized an additional gain of approximately $0.2 million related to the sale of these interests. These interests were part of the Electric Utility segment.

See Note 6 for additional asset sales by the Company.

6. Impairment of Assets

Processing and Compression Assets

In April 2002, in response to unsatisfactory operating results, including the negative impact of lower natural gas and natural gas liquids prices, a comprehensive review of the Enogex strategy and operations was undertaken. From an operational perspective, this review of the utilization of gathering and processing assets demonstrated that Enogex had too much compression horsepower installed and that there was excess capacity at the natural gas processing plants. As a result of the review, a plan was developed to remove excess compressors from the pipeline system. By removing excess compressor capacity from the system, fuel and operation and maintenance costs were reduced. The review of the operations of the natural gas processing plants also identified opportunities to consolidate natural gas volumes at certain processing plants and to bypass others. As a result of consolidating these volumes, the utilization of the natural gas processing plants was maximized and the bypassed plants were taken out of service. As the equipment was removed, the strategy dictated that idle assets be disposed of so that the proceeds could be used for capital expenditures in other areas or to pay down the Company s debt.

As a result of decisions made to remove these assets from service and to dispose of them, an evaluation of the fair value of the assets was made. Since the fair value of these assets was less than

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the carrying value of the assets, the Company recorded a pre-tax impairment loss of approximately $48.3 million in the Natural Gas Pipeline segment during the fourth quarter of 2002.

The planning for the marketing of these assets commenced late in 2002, when a position was created at Enogex to manage assets and, if necessary, liquidate any surplus assets. The natural gas processing plants were actively marketed during 2003; however, the Company had limited success in disposing of these plants in 2003. Other operators in the mid-continent region either were not expanding operations or also were marketing natural gas processing plants. Therefore, there was very little activity in the region for natural gas processing plants. Efforts were made to market the natural gas processing plants in the international market; however, these efforts also were not successful.

Efforts to sell the excess compressor assets during 2003 faced similar market conditions and similar difficulties. As a result, Enogex s business development group, as part of their efforts to dispose of the compressor assets, began negotiating in 2003 with an independent party to form a joint venture that would rent out the compressors. Certain of these impaired assets were contributed to the joint venture discussed below.

Also during 2003, another evaluation of the horsepower of compression needed to meet the operational requirements of the Company s gathering and transmission system was performed based on the changed market conditions. The review identified additional compressor equipment that could be removed from the system and an additional pre-tax impairment loss of approximately $9.2 million was recorded in the Natural Gas Pipeline segment in the fourth quarter of 2003 to recognize the difference between the carrying value of these units and their fair value expected to be realized in a disposal. Certain of these impaired assets were contributed to the joint venture discussed below. The impairments recorded in the fourth quarters of 2002 and 2003 resulted from plans to dispose of these assets at prices below the carrying amount. The fair value of these assets was determined based on third-party evaluations, prices for similar assets, historical data and projected cash flows.

During the year ended December 31, 2004, the Company sold certain of its compression and processing assets for approximately $5.0 million and recognized an after tax gain of approximately $1.8 million related to the sale of these assets. The carrying amount of the remaining assets (that were the subject of the impairment charges in the fourth quarters of 2002 and 2003) was approximately $2.6 million and $11.9 million at December 31, 2004 and 2003, respectively. As discussed below, for any remaining assets that were the subject of the impairment charges in the fourth quarters of 2002 and 2003, the Company has either contributed the assets to the joint venture or reclassified these assets from held for sale to held and used as of December 31, 2004.

During the third quarter of 2004, Enogex entered into a joint venture arrangement with a third party and contributed certain of its natural gas compression assets (with a carrying amount of approximately $3.9 million) to the joint venture. The objective of the joint venture is to derive value from the assets by renting the natural gas compressors. Enogex Compression was created to act as the participating entity in the joint venture. Enogex Compression holds a majority ownership in the joint venture, although the actual ownership percentages may fluctuate based on the relative capital contributions of Enogex Compression and the third party member. The third party acts as the manager and conducts the daily operations of the joint venture. These assets are part of the Natural Gas Pipeline segment.

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During the third quarter of 2004, the Company reclassified an asset in the Natural Gas Pipeline segment from assets held for sale to assets held and used. This asset had a carrying amount of approximately $0.8 million at the time the asset was reclassified. This decision to reclassify the asset was based on the fact that when this asset was previously impaired, there was a declining natural gas processing market, declining volumes and a decline in the British thermal unit content of the gas flowing through the processing plants. Since the time of impairment, natural gas prices have increased and, with higher sustained natural gas prices, drilling activity has also significantly increased. Also, new producing wells are also producing richer natural gas that must be processed. As a result, in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, if a long-lived asset is reclassified from assets held for sale to assets held for use, the long-lived asset should be measured at the lower of its carrying amount before the asset was classified as held for sale less any depreciation expense that would have been recognized had the asset been continuously classified as held and used or its fair value at the date of the subsequent decision not to sell. The Company determined the fair value of this asset, which was less than the carrying amount described above, based on historical data and projected cash flows and recorded a gain of approximately $0.3 million during 2004 related to reclassifying this asset from assets held for sale to assets held and used, which was recorded as a credit to Impairment of Assets in the Consolidated Statement of Income.

In October 2004, the Company reclassified a large electric driven compressor in the Natural Gas Pipeline segment that was previously classified as assets held for sale to assets held and used. This compressor had a carrying amount of approximately $1.2 million at September 30, 2004. This decision was based on the fact that, when this asset was previously impaired, there was excess horsepower available for compression on the pipeline system and this asset was identified as surplus that would be sold. Since the time of impairment, it has become economical to reactivate this compressor due to higher fuel costs related to natural gas-fired compression and changes to the compression requirements for the pipeline. As a result, in accordance with SFAS No. 144, if a long-lived asset is reclassified from assets held for sale to assets held for use, the long-lived asset should be measured at the lower of its carrying amount before the asset was classified as held for sale less any depreciation expense that would have been recognized had the asset been continuously classified as held and used or its fair value at the date of the subsequent decision not to sell. The Company determined the fair value of this asset, which was less than the carrying amount described above, based on a third party valuation of the asset and, as based on this valuation, the Company recorded an additional impairment charge of approximately $0.3 million during the fourth quarter of 2004 related to reclassifying this asset from assets held for sale to assets held and used, which was recorded in Impairment of Assets in the Consolidated Statement of Income.

In December 2004, the Company reclassified several compressors and processing plants in the Natural Gas Pipeline segment that were previously classified as assets held for sale to assets held and used. These assets had a carrying amount of approximately $1.6 million at December 31, 2004. This decision was based on the fact that these assets are no longer being marketed and the Company believes the value of the future benefit of holding these assets exceeds the current fair market value. As a result, in accordance with SFAS No. 144, if a long-lived asset is reclassified from assets held for sale to assets held for use, the long-lived asset should be measured at the lower of its carrying amount before the asset was classified as held for sale less any depreciation expense that would have been recognized had the asset been continuously classified as held and used or its fair value at the date of the subsequent decision not to sell. The Company determined the fair value of these assets, which was less than the carrying amount described above, based on a third party valuation of the assets and, as a result, the Company recorded a net gain of approximately $0.8

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million during the fourth quarter of 2004 related to reclassifying these assets from assets held for sale to assets held and used, which was recorded as a credit to Impairment of Assets in the Consolidated Statement of Income.

Pipeline Assets

During the third quarter of 2004, the Company recognized a pre-tax impairment loss of approximately $8.6 million in the Natural Gas Pipeline segment related to Enogex natural gas pipeline assets. 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 connection with the preparation of the third quarter 2004 financial statements, Enogex performed an evaluation on these assets and concluded that an impairment charge needed to be recorded. The primary reason for this determination was that these four pipeline asset segments were originally built for the specific purpose of providing gas transmission service to this customers four power plants that have been or are in the process of being shut down, and, as a result, other alternative commercial uses for these facilities are considered unlikely. The fair value of these assets was determined based on historical data and projected cash flows. Following the impairment charge, the carrying amount of these assets was approximately $0.9 million at September 30, 2004. The depreciation lives for these assets as of September 30, 2004 were revised based on these circumstances. During the fourth quarter of 2004, additional depreciation of approximately $0.7 million and an additional impairment charge of approximately $0.2 million were recorded related to these assets. In December 2004, the Company received notification that all of this customers plants in West Texas had shut down and service is no longer required. The Company is currently evaluating other commercial opportunities for these assets as well as contacting other parties that may be interested in acquiring any of these assets.

7. 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)*	**2004**	2003	2002
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Power plant long-term service agreement	$ **6.0**	$ ---	$ ---
Issuance of common stock	**2.2**	11.4	5.6
Change in fair value of long-term debt due to interest rate swaps	**0.3**	(8.3)	18.3
Change in property, plant and equipment due to transfer of inventory	**---**	7.1	---
Assumption of asset and related debt	**---**	---	42.5
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $1.7, $0.5, $0.9)	**$ 85.2**	$ 92.6	$ 109.7
Income taxes (net of income tax refunds)	**37.4**	(33.2)	28.2

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8. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2004**	2003	2002

Provision (Benefit) for Current Income Taxes from Continuing Operations			
Federal	**$ 22.2**	$ (35.8)	$ 12.5
State	**2.5**	(6.1)	(0.6)
Total Provision (Benefit) for Current Income Taxes from Continuing Operations	**24.7**	(41.9)	11.9
Provision for Deferred Income Taxes, net from Continuing Operations			
Federal	**53.5**	105.3	31.7
State	**4.8**	16.1	6.6
Total Provision for Deferred Income Taxes, net from Continuing Operations	**58.3**	121.4	38.3
Deferred Investment Tax Credits, net	**(5.2)**	(5.2)	(5.2)
Income Taxes Relating to Other Income and Deductions	**2.4**	(0.6)	(0.4)
Total Income Tax Expense from Continuing Operations	**$ 80.2**	$ 73.7	$ 44.6

In connection with the filing in the third quarter of 2003 of the Company s consolidated income tax returns for 2002, the Company elected to change its tax method of accounting related to the capitalization of costs for self-constructed assets to another method prescribed in the Treasury regulations. The accounting method change is for income tax purposes only. For financial accounting purposes, the only change is recognition of the impact of the cash flow generated by accelerating income tax deductions. This is 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 have been refunded. Estimates made for 2003 were applied to 2004. As a result of this tax net operating loss, tax credits associated with Enogex s natural gas production were not realized during 2003 and resulted in approximately $1.8 million in higher income tax expense in discontinued operations. The Company received federal and state income tax refunds of approximately $50.8 million during 2003 related to this tax accounting method change.

The following schedule reconciles the statutory federal tax rate to the effective income tax rate:

Year ended December 31	**2004**	2003	2002
Statutory federal tax rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	**2.0**	3.1	3.1
Tax credits, net	**(2.2)**	(2.5)	(4.1)
Other, net	**(0.4)**	(0.4)	1.5
Effective income tax rate as reported	**34.4%**	35.2%	35.5%

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

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utility property have been deferred and are being amortized to income over the life of the related property.

The Company follows the provisions of SFAS No. 109, Accounting for Income Taxes, 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, 2004 and 2003, respectively, are as follows:

(In millions)	**2004**	2003
Current Accumulated Deferred Tax Assets		
Accrued vacation	**$ 6.0**	$ 5.8
Uncollectible accounts	**1.8**	1.4
Other	**5.9**	2.2
Total Current Accumulated Deferred Tax Assets	**$ 13.7**	$ 9.4
Non-Current Accumulated Deferred Tax Liabilities		
Accelerated depreciation and other property related differences	**$ 768.3**	$ 710.4
Allowance for funds used during construction	**31.1**	33.1
Income taxes refundable to customers, net	**11.9**	12.2
Bond redemption-unamortized costs	**7.3**	7.7
Company pension plan	**2.6**	8.9
Other	**1.3**	(6.1)
Total Non-Current Accumulated Deferred Tax Liabilities	**822.5**	766.2
Non-Current Accumulated Deferred Tax Assets		
Deferred federal investment tax credits	**(10.3)**	(12.1)
Postretirement medical and life insurance benefits	**(10.2)**	(6.8)
Total Non-Current Accumulated Deferred Tax Assets	**(20.5)**	(18.9)
Non-Current Accumulated Deferred Income Tax Liabilities, net	**$ 802.0**	$ 747.3

OG&E has an Oklahoma investment tax credit (ITC) carryover of approximately $3.3 million. These ITC carryover amounts will begin expiring in the year 2017. OG&E believes that, based on current projections, these ITC carryover amounts will be fully utilized in 2005.

American Jobs Creation Act of 2004

On October 22, 2004, President Bush signed into law the American Jobs Creation Act of 2004 (the Jobs Creation Act). The Jobs Creation Act amended and added a significant number of provisions to the Internal Revenue Code and these changes affect virtually all taxpayers. The Jobs Creation Act includes a provision that entitles all U.S. manufacturers with qualified manufacturing activities to a Deduction Related to Production Activities (DRPA). Certain activities of the Company, including the generation of electricity and the processing of natural gas, are included in the list of qualifying manufacturing activities for purposes of the DRPA. Thus, the Company believes that the DRPA could impact the Company s future effective income tax rate.

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Beginning in 2005, the DRPA equals three percent of the lesser of: (a) taxable income derived from a qualified production activity; or (b) overall taxable income for the taxable year. However, the deduction for a taxable year is limited to 50 percent of the Form W-2 wages paid by a taxpayer during the taxable year in which the deduction is claimed. The deduction percentage increases to six percent in 2007. In 2010, when the deduction is fully phased-in, the deduction rate will be nine percent.

Because OG&E is an integrated electric utility and Enogex is an integrated natural gas transportation company, both will be required to allocate income and expenses to their qualified production activity. The U.S. Treasury Department issued guidance related to the DRPA on January 19, 2005 and this guidance provides rules for determining taxable income when a portion of a taxpayer s income is derived from a qualified production activity. The FASB has determined that the DRPA will be classified as a special deduction for purposes of computing income tax expense which will have the effect of reducing the Company s overall effective tax rate to the extent the Company can claim a deduction. The Company is in the process of analyzing these rules to determine the effect of the DRPA on its overall effective tax rate and income tax expense.

9. Common Stock

In April 2003, the Company filed a Form S-3 Registration Statement registering the sale of up to $130.0 million of unsecured debt securities or shares of the Company s common stock. On August 27, 2003 and September 5, 2003, respectively, the Company issued 4,650,000 shares and 674,074 shares of its common stock under this registration statement at a public offering price of $21.60 per share.

In April 2003, 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 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. During the year ended December 31, 2003, the Company issued 615,721 shares of common stock and 1,855,989 shares of common stock at a discount of 1.75 percent and 1.50 percent, respectively, pursuant to the DRIP/DSPP. Also, as part of the DRIP/DSPP, the Company issued 242,003 shares of common stock, 938,497 shares of common stock and 499,397 shares of common stock at no discount during the years ended December 31, 2004, 2003 and 2002, respectively.

For the years ended December 31, 2004 and 2003, respectively, there were 392,686 shares of new common stock and 134,098 shares of new common stock issued pursuant to the Company s Stock Incentive Plan, related to exercised stock options.

At December 31, 2004, there were 10,058,491 shares of unissued common stock reserved for the various employee and Company stock plans. Beginning July 30, 2002, the Company issued new common stock to satisfy the common stock requirements of the DRIP/DSPP rather than purchasing the common stock on the open market. Effective December 1, 2003, the Company began purchasing common stock on the open market to satisfy the common stock requirements of

the DRIP/DSPP. Beginning August 1, 2004, the Company issued new common stock to satisfy the common stock requirements of the DRIP/DSPP rather than purchasing the common stock on the open market. Effective January 1, 2005, the Company began purchasing common stock on the open market to satisfy the common stock requirements of the DRIP/DSPP.

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.

10. Stock Incentive Plan

On January 21, 1998, the Company adopted a Stock Incentive Plan (the 1998 Plan). Under this Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees. The Company had authorized the issuance of up to 4,000,000 shares under 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.

Restricted Stock

During 2004 and 2003, no restricted stock was distributed under the Plans. The restricted stock previously distributed vests at the end of three years. Each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. Awards of restricted stock are subject to an additional condition with all or a portion of the shares of restricted stock being subject to forfeiture based on the Company s return on equity compared to a peer group of companies during the three-year restriction period.

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Performance Units

During 2004 and 2003, respectively, the Company awarded 162,591 performance units and 128,469 performance units to certain employees of the Company. These performance units represent the value of one share of the Company s common stock. These performance units are contingently awarded and will be payable in cash or shares of the Company s common stock subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a three-year award cycle is dependent on the Company s total shareholder return relative to the total shareholder return of a peer group of companies. Each performance unit is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement.

Stock Options

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. To date, no options have expired unexercised. Stock option transactions related to the Plans are summarized in the following table:

	2004		2003		2002	
	Number of Options	**Weighted Average Price**	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Options Outstanding at beginning of year	**2,871,802**	**$21.6253**	2,419,360	$23.4400	1,570,027	$24.0475
Granted	**380,400**	**23.5750**	838,700	16.6850	959,600	22.2716
Exercised	**(392,686)**	**19.5590**	(134,098)	18.8174	(10,199)	18.2500
Cancelled	**(31,602)**	**23.2500**	(252,160)	24.0963	(100,068)	22.2988
Options Outstanding at end of year	**2,827,914**	**$22.1564**	2,871,802	$21.6253	2,419,360	$23.4400
Options Exercisable at end of year	**1,809,441**	**$23.2946**	1,408,255	$24.2019	1,202,053	$24.8966

The fair value of each option grant under the Plans for the years ended December 31, 2004, 2003 and 2002, are estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants in 2004, 2003 and 2002:

	2004	2003	2002
Expected dividend yield	**6.27%**	6.30%	6.05%
Expected price volatility	**18.58%**	22.06%	22.95%
Risk-free interest rate	**3.77%**	3.80%	4.90%
Expected life of options (in years)	**7**	7	7
Weighted-average fair value of options granted	**$ 2.05**	$ 1.85	$ 3.10

The following table provides additional information about stock options outstanding at December 31, 2004:

		Options Outstanding		Options Exercisable	
Range of Exercise Prices	Weighted-Average Remaining Contractual Life	Number Outstanding	Weighted-Average Exercise Price	Number Outstanding	Weighted-Average Exercise Price
$16.69 - $22.70	7.11 years	1,789,214	$ 19.9781	1,099,241	$ 20.9083
$23.58 - $28.75	5.33 years	1,038,700	$ 25.9086	710,200	$ 26.9880

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11. 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)*	**2004**	2003	2002
Average Common Shares Outstanding			
Basic average common shares outstanding	**88.0**	81.8	78.1
Effect of dilutive securities:			
Employee stock options and unvested stock grants	**0.3**	0.1	0.1
Contingently issuable shares (performance units)	**0.2**	0.2	---
Diluted average common shares outstanding	**88.5**	82.1	78.2

For the years ended December 31, 2004, 2003 and 2002, respectively, approximately 0.6 million shares, 1.7 million shares and 1.7 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.

12. Trust Originated Preferred Securities

On October 21, 1999, OGE Energy Capital Trust I issued $200.0 million principal amount of 8.375 percent trust preferred securities that mature on October 15, 2039. Distributions paid by the financing trust were financed through payments on debt securities issued by the Company and held by the financing trust. Distributions paid to preferred security holders are recorded as Interest Expense on Trust Preferred Securities in the Consolidated Statements of Income for the year ended December 31, 2002. The Company adopted FASB Interpretation No. 46 on December 31, 2003 which resulted in the trust preferred securities being deconsolidated in the Company s Consolidated Financial Statements for the year ended December 31, 2003. As a result of deconsolidating the trust preferred securities, there was a non-cash increase in Other Property and Investments and Long-Term Debt Unconsolidated Affiliate of approximately $6.2 million in the Consolidated Balance Sheet at December 31, 2003. Also, distributions paid to preferred security holders are recorded as Interest Expense Unconsolidated Affiliate in the Consolidated Statements of Income for the year ended December 31, 2003. On October 15, 2004, the Company caused all of the outstanding trust preferred securities to be redeemed at $25 per share (100 percent of liquidation value). The redemption was initially funded with cash on hand and approximately $170.0 million in commercial paper. The Company refinanced a portion of this short-term debt with $100.0 million of long-term debt issued in November 2004. In October 2004, the Company wrote off approximately $5.9 million related to unamortized debt issuance costs for the trust preferred securities which is included in Interest on Short-term Debt and Other Interest Charges in the Consolidated Statement of Income.

13. Long-Term Debt

A summary of the Company s long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2004, the Company is in compliance with all of its debt agreements.

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Long-Term Debt with Optional Redemption Provisions

OG&E s 6.500 percent Senior Notes (Senior Notes) series due July 15, 2017, were repayable on July 15, 2004, at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to July 15, 2004. Only holders who submitted requests for repayment between May 15, 2004 and June 15, 2004 were entitled to such repayments. OG&E and the Senior Note Trustee received no such requests for repayment of the Senior Notes.

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 are redeemable at the option of the holder during the next 12 months, are as follows:

SERIES	DATE DUE	AMOUNT

Variable %	Garfield Industrial Authority, January 1, 2025	$	**47.0**
Variable %	Muskogee Industrial Authority, January 1, 2025		**32.4**
Variable %	Muskogee Industrial Authority, June 1, 2027		**56.0**
Total (redeemable during next 12 months)		**$**	**135.4**

All of these Bonds are subject to redemption at the option 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. A third party remarketing agent for the Bonds will attempt to remarket any Bonds tendered for purchase. 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 liquidity to meet these obligations.

Early Retirement of Long-Term Debt

In 1998, Enogex issued a note in the amount of approximately $5.7 million payable to an unaffiliated former partial interest owner of NOARK. The note had a maturity date of July 1, 2020 and an interest rate of 7.00 percent. Principal and interest payments of approximately $0.8 million were due annually beginning July 1, 2004. In July 2004, Enogex made the initial $0.8 million payment and also made a payment of approximately $7.8 million, which included accrued interest since inception of the note, to repay the outstanding note balance and satisfy its remaining obligations related to this note. Enogex recorded a pre-tax gain of approximately $0.1 million in the third quarter of 2004 related to this transaction.

Issuance of Long-Term Debt

In August 2004, OG&E issued $140.0 million of long-term debt. The proceeds were used to replace a portion of the short-term borrowings initially used to fund a portion of the McClain Plant acquisition in July 2004. This debt has a maturity date of August 1, 2034 and an interest rate of 6.50 percent.

In September 2004, the Company filed a Form S-3 Registration Statement registering the sale of up to $200.0 million of the Company s unsecured debt securities. In November 2004, the Company issued $100.0 million of long-term debt, the proceeds of which were used to replace a portion of the short-term debt incurred to fund the redemption of the trust preferred securities on October 15, 2004. This new debt has a maturity date of November 15, 2014 and an interest rate of 5.00 percent.

Non-recourse Debt of Joint Venture

On June 15, 1998, NOARK issued $80.0 million of long-term notes in a private placement. The Company guaranteed 40 percent of these notes, while the joint venture partner guaranteed 60 percent of the notes. The notes mature on June 1, 2018, and require semi-annual principal payments of $1.0 million plus interest at a fixed rate of 7.15 percent with a final balloon payment of $40 million due at maturity. The Company s portion of the semi-annual principal payments is approximately $0.4 million. The joint partner s portion of this long-term debt is included in Non-recourse Debt of Joint Venture in the Consolidated Balance Sheets.

Interest Rate Swap Agreements

Fair Value Hedges

At December 31, 2004 and 2003, the Company had three outstanding interest rate swap agreements that qualified as fair value hedges: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate (LIBOR) and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert a total of $200.0 million ($100.0 million for each interest rate swap agreement) of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR in arrears. The objective of these 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. These interest rate swaps qualified as fair value hedges under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At December 31, 2004 and 2003, the fair values pursuant to the interest rate swaps were approximately $7.9 million and $7.6 million, respectively, and the hedges were classified as Deferred Charges and Other Assets Price Risk Management in the Consolidated Balance Sheets. A corresponding net increase of approximately $7.9 million and $7.6 million was reflected in Long-Term Debt at December 31, 2004 and 2003, respectively, as these fair value hedges were effective at December 31, 2004 and 2003.

Cash Flow Hedges

The Company entered into four separate interest rate swap agreements, effective April 16, 2004, April 21, 2004, May 17, 2004 and July 16, 2004, respectively, to hedge approximately $20.0 million, $30.0 million, $20.0 million and $10.0 million, respectively, of future interest payments of long-term debt that was issued in November 2004. See Note 1 for a further discussion of these interest rate swap agreements.

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Long-term Debt Maturities

During 2004 and 2003, approximately $51.0 million and $19.0 million, respectively, of Enogex s long-term debt matured and approximately $10.3 million and $12.0 million, respectively, was redeemed during 2004 and 2003 which is itemized in the following table.

(In millions)	**2004**	2003
Series Due 2003 -- 6.60% - 8.28%	**$ ---**	$ 19.0
Series Due 2004 -- 6.71% - 8.34%	**51.0**	---
Series Due 2018 -- 7.15%	**2.0**	2.0
Series Due 2020 -- 7.00%	**8.3**	---
Series Due 2023 -- 7.75%	**---**	10.0
Total	**$ 61.3**	$ 31.0

Maturities of the Company s long-term debt during the next five years consist of $146.1 million in 2005; $1.8 million in 2006; $4.8 million in 2007; $2.8 million in 2008 and $1.8 million in 2009. For OG&E, $110.0 million of long-term debt matures in 2005; however, in the Consolidated Statement of Capitalization at December 31, 2004, no amount is shown as Long-Term Debt Due Within One Year. The Company plans to refinance this amount and the Company believes they have the ability to do so as the Company and OG&E entered into new five-year revolving credit agreements in October 2004 in an amount up to $550 million which could be utilized to temporarily finance these notes when they mature in October 2005.

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 Other 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 maximum and average amounts of short-term borrowings during 2004 on a consolidated basis were approximately $216.1 million and $44.7 million, respectively, at a weighted average interest rate of 2.91 percent. The weighted average interest rates for 2003 and 2002 were 1.67 percent and 2.40 percent, respectively.

The short-term debt balance was approximately $125.0 million and $202.5 million at December 31, 2004 and 2003, respectively. The balance at December 31, 2003 was primarily due to the incurrence of short-term debt in anticipation of the expected 2003 year-end closing of the acquisition of the McClain Plant, which was completed on July 9, 2004. In conjunction with the acquisition of the McClain Plant, the Company issued short-term debt to fund a portion of the acquisition, and, as a result, the short-term debt balance was approximately $216.1 million at July 31, 2004. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings. During October 2004, the Company issued approximately $170.0 million in commercial paper related to the redemption of the trust preferred securities, of which approximately $100.0 million was refinanced in November 2004 by the issuance of long-term debt. See Note 18 for a further discussion of the recent McClain Plant acquisition.

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The following table shows the Company s lines of credit in place and available cash at December 31, 2004. At December 31, 2004, the Company s short-term borrowings consisted of commercial paper.

Lines of Credit and Available Cash *(In millions)*

Entity		Amount Available		Amount Outstanding	Maturity
OGE Energy Corp.	$	15.0	$	---	April 6, 2004
OG&E		100.0		---	October 20, 2009 (B)
OGE Energy Corp. (A)		450.0		---	October 20, 2009 (B)
		565.0		---	
Cash		26.4		N/A	N/A
Total	$	591.4	$	---	

(A) The lines of credit are used to back up a maximum of $300.0 million of the Company s commercial paper borrowings, which were approximately $125.0 million at December 31, 2004.
(B) Each of the new credit facilities has a five-year term with two options to extend the term for one year.

On October 20, 2004, the Company and OG&E entered into revolving credit agreements totaling $550 million. These agreements include two separate credit facilities, one for the Company in an amount up to $450 million and one for OG&E in an amount up to $100 million. Each of the new credit facilities has a five-year term with two options to extend the term for one year.

The Company s and OG&E s ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade. Their respective back-up lines of credit contain rating grids that require annual fees and borrowing rates to increase if they suffer an adverse ratings impact. 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 $400 million in short-term borrowings at any one time. In November 2004, OG&E received approval from the FERC to incur up to $400 million in short-term borrowings for an additional two-year period beginning January 1, 2005 through December 31, 2006.

15. Retirement Plans and Postretirement Benefit Plans

In December 2003, the FASB issued SFAS No. 132 (Revised), Employer s Disclosures about Pension and Postretirement Benefits, an amendment of FASB Statements No. 87, 88 and 106, which revised the disclosure requirements applicable to employers pension plans and other postretirement benefit plans. This Statement requires additional disclosures for defined benefit pension plans and other defined benefit postretirement plans, including disclosures describing the components of net periodic benefit cost recognized during interim periods.

Defined Benefit Pension Plan

All eligible employees of the Company are covered by a non-contributory defined benefit pension plan. In early 2000, the Board of Directors approved significant changes to the pension plan. Prior to these changes, benefits were 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

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retirement, with reductions in benefits for each year prior to age 62 that an employee retired and additional significant reductions for retirement prior to age 55. The changes made in 2000 included: (i) elimination of the significant reduction for employees electing to retire before age 55; (ii) the addition of an alternative method of computing the reduction in benefits (based on years of service and age); and (iii) the ability of an employee at time of retirement to receive, in lieu of an annuity, a lump sum payment equal to the present value of the annuity. Also, for employees hired after January 31, 2000, the pension plan will be 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 the benefit based on final average compensation as described above.

It is the Company s policy to fund the plan on a current basis based on the net periodic SFAS No. 87 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 2004 and 2003, the Company made contributions of approximately $69.0 million and $50.0 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. During 2005, the Company plans to contribute approximately $37.4 million to the 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 requirements specified by the Employee Retirement Income Security Act of 1974.

During 2004 and 2003, the Company made contributions to the pension plan and the restoration of retirement income plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2004 and 2003 of approximately $92.0 million and $55.7 million, respectively. At December 31, 2004 and 2003, the Company s projected pension benefit obligation exceeded the fair value of the pension plan assets and the restoration of retirement income plan assets by approximately $123.3 million and $131.8 million, respectively. 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, Employers Accounting for Pensions, required the recognition of an additional minimum liability in the amount of approximately $156.6 million and $137.6 million, respectively, at December 31, 2004 and 2003. 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 2004 or 2003 and did not require a usage of cash and is therefore excluded from the Consolidated Statements 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.

The 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, 2004 and 2003:

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	2004	2003
Equity securities	**62 %**	61 %
Debt securities	**36 %**	38 %
Other securities	**2 %**	1 %
Total	**100 %**	100 %

Investment Policies and Strategies

The plan assets are held in a master trust which follows an investment policy and strategy designed to maximize the long-term investment returns of the master 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 Employees Benefit Funds Management Requirements Committee (the Committee).

The various investment managers used by the master 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 a periodic 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 master 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) 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
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	Russell Midcap Index
Small-Cap Equity	Russell 2000 Index
Global 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 master 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. Exposure to any single non-government issue is limited to three percent. At least 80 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), Fitch Ratings (Fitch) or Duff & Phelps LLC. The manager may invest up to 10 percent of the portfolio s market value in cash equivalents (securities with less than six months to maturity). 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. No mortgage derivatives or structured notes are permitted. The purchase of any of the Company s equity, debt or other securities is prohibited unless prior approval of the Committee is received.

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 mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell Midcap, small dividend yield, return on equity at or near the Russell Midcap and earnings per share growth rate at or near the Russell Midcap. The 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 global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall master 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.

For all equity investment managers, 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

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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). A minimum of 95 percent of the total assets of an equity manager s portfolio must be allocated to the equity markets. 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 or fund for re-deployment. The purchase of any of the Company s equity, debt or other securities is prohibited unless prior approval of the Committee is received. The purchase of equity or debt issues of the portfolio manager s organization is also prohibited unless prior approval of the Committee is received.

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 service total or exceed 80 or have attained age 55 with 10 years of service at the time of retirement are entitled to these postretirement benefits. Employees hired after January 31, 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.

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:

Projected Benefit Obligations

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2004**	2003	**2004**	2003
Beginning obligations	**$ (485.4)**	$ (443.0)	**$ (181.1)**	$ (183.1)
Service cost	**(16.9)**	(15.2)	**(3.0)**	(3.0)
Interest cost	**(29.7)**	(29.2)	**(11.1)**	(10.9)
Participants contributions	---	---	**(3.0)**	(2.2)
Plan changes/other	**(7.2)**	(4.0)	---	---
Actuarial gains (losses)	**(56.0)**	(42.3)	**(7.0)**	6.6
Benefits paid	**47.0**	48.3	**12.9**	11.5
Ending obligations	**$ (548.2)**	$ (485.4)	**$ (192.3)**	$ (181.1)

Fair Value of Plans Assets

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2004**	2003	**2004**	2003
Beginning fair value	**$ 353.6**	$ 286.3	**$ 56.0**	$ 46.0
Actual return on plans assets	**46.6**	65.6	**9.3**	10.0
Employer contributions	**71.7**	50.0	**8.6**	9.3
Participants contributions	---	---	**3.0**	2.2
Benefits paid	**(47.0)**	(48.3)	**(12.9)**	(11.5)
Ending fair value	**$ 424.9**	$ 353.6	**$ 64.0**	$ 56.0

Net Periodic Benefit Cost

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
(In millions)	**2004**	2003	2002	**2004**	2003	2002
Service cost	**$ 16.9**	$ 15.2	$ 13.3	**$ 3.0**	$ 3.0	$ 2.7
Interest cost	**29.7**	29.2	28.7	**11.1**	10.9	9.6
Return on plan assets	**(31.6)**	(24.3)	(26.9)	**(5.5)**	(5.5)	(5.6)
Amortization of transition obligation	---	---	---	**2.7**	2.7	2.7
Amortization of net loss	**11.9**	13.2	4.7	**4.9**	3.4	0.5
Amortization of unrecognized prior service cost	**6.3**	5.8	5.4	**2.1**	2.1	2.1
Net periodic benefit cost	**$ 33.2**	$ 39.1	$ 25.2	**$ 18.3**	$ 16.6	$ 12.0

The capitalized portion of the net periodic pension benefit cost was approximately $8.4 million, $5.8 million and $4.0 million at December 31, 2004, 2003 and 2002, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $5.0 million, $2.6 million and $2.0 million at December 31, 2004, 2003 and 2002, respectively.

Funded Status of Plans

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2004**	2003	**2004**	2003
Funded status of the plans	**$ (123.3)**	$ (131.8)	**$ (128.3)**	$ (125.1)
Unrecognized net loss	**175.6**	146.6	**63.4**	65.1
Unrecognized prior service cost	**39.7**	40.9	**9.2**	11.2
Unrecognized transition obligation	---	---	**22.0**	24.7

Net amount recognized	**$ 92.0**	$ 55.7	**$ (33.7)**	$ (24.1)

Amounts recognized in the Consolidated Balance Sheets consist of:

	Pension Plan and Restoration of Retirement Income Plan	
(In millions)	**2004**	2003
Prepaid benefit obligation	**$ 92.7**	$ 55.7
Accrued pension and benefit obligations	**(157.3)**	(137.6)
Intangible asset - unamortized prior service cost	**38.0**	40.2
Accumulated deferred tax asset	**45.9**	37.7
Accumulated other comprehensive loss, net of tax	**72.7**	59.7
Net amount recognized	**$ 92.0**	$ 55.7

Rate Assumptions

	Pension Plan			Postretirement Benefit Plans		
	2004	2003	2002	**2004**	2003	2002
Discount rate	**5.75%**	6.25%	6.75%	**5.75%**	6.25%	6.75%
Rate of return on plans assets	**8.75%**	8.75%	9.00%	**8.75%**	8.75%	9.00%
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	**10.00%**	11.00%	12.00%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2010**	2010	2010

N/A - not applicable

The overall expected rate of return on plan assets assumption remained 8.75 percent in 2003 and 2004 in determining net periodic pension 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 $59.5 million in 2005, $58.8 million in 2006, $56.0 million in 2007, $58.9 million in 2008, $60.8 million in 2009 and $288.7 million in years 2010 to 2014. 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. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE

(In millions)	**2004**	2003	2002

ONE-PERCENTAGE POINT INCREASE

Effect on aggregate of the service and interest cost components	**$ 1.9**	$ 1.9	$ 1.6
Effect on accumulated postretirement benefit obligations	**24.2**	23.1	23.2

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ONE-PERCENTAGE POINT DECREASE

(In millions)	**2004**	2003	2002
Effect on aggregate of the service and interest cost components	**$ 1.5**	$ 1.5	$ 1.3
Effect on accumulated postretirement benefit obligations	**19.8**	18.9	19.0

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Medicare Act). The Medicare Act expanded Medicare to include, for the first time, coverage for prescription drugs. Due to various uncertainties related to the Company s response to this legislation in relation to its postretirement medical plan and the appropriate accounting methodology for this event, the Company elected to defer financial recognition of this legislation until the FASB issued final accounting guidance. This deferral election was permitted under FASB Staff Position No. FAS 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. 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 provides 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 requires those employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. For employers who elected to defer financial recognition, FAS 106-2 provides two alternative methods of adoption which include a retroactive application to the date of the Medicare Act s enactment or a prospective application as of the date of adoption. For employers who elected not to defer financial recognition, FAS 106-2 requires these employers to recognize a cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20. Adoption of FAS 106-2 is required for financial statements issued for periods beginning after June 15, 2004. 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 s postretirement medical plan will be reduced by approximately $13.3 million as a result of savings to the Company s postretirement medical plan resulting from the Medicare Act, which will reduce the Company s costs for its postretirement medical plan by approximately $2.5 million annually. The $2.5 million in annual savings is comprised of a reduction of approximately $1.5 million from amortization of the $13.3 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $0.8 million and a reduction in the service cost due to the subsidy of approximately $0.2 million.

The Company expects to pay gross benefits payments related to its postretirement benefit plans, including prescription drug benefits, of approximately $11.3 million in 2005, $11.2 million in 2006, $11.2 million in 2007, $11.9 million in 2008, $12.5 million in 2009 and $71.5 million in years 2010 to 2014. The Company expects to receive subsidy receipts related to its postretirement benefit plans of approximately $0.5 million in 2006, $0.6 million in 2007, $0.6 million in 2008, $0.7 million in 2009 and $4.0 million in years 2010 to 2014. The Company does not expect to receive any subsidy receipts in 2005.

Defined Contribution Plan

The Company provides a defined contribution savings plan. Each regular full-time employee of the Company or an affiliate is eligible to participate in the plan immediately. All other

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employees of the Company or an 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. 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 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 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. The Company contributed approximately $6.2 million, $5.6 million and $5.2 million during 2004, 2003 and 2002, 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.

Eligible employees who enroll in the plan may elect to defer up to a maximum of 70 percent of base salary and 100 percent of bonus awards; however, the Benefits Committee, appointed by the Benefits Oversight Committee (which consists of at least two members appointed by the Board of Directors) may, at its discretion, permit participants to 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 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 in this plan as Accrued Pension and Benefit Obligations and Other Deferred Credits and 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.

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Supplemental Executive Retirement Plan

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

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. Enogex also has been involved in investing in the development for and production of natural gas and crude oil, which investments Enogex sold during 2002. For the year ended December 31, 2002, Other Operations primarily includes unallocated corporate expenses, interest expense on the trust preferred securities and interest expense on commercial paper. As a result of the adoption of FASB Interpretation No. 46 on December 31, 2003, and the resulting deconsolidation of the trust preferred securities and the consolidation of MBP 19, Other Operations for the year ended December 31, 2003 primarily includes unallocated corporate expenses, interest expense to unconsolidated affiliate, interest expense on commercial paper and MBP 19. However, MBP 19 was deconsolidated during the first quarter of 2004. See Note 2 for a further discussion of the accounting for MBP 19. Therefore, Other Operations for the year ended December 31, 2004 primarily includes unallocated corporate expenses, interest expense to unconsolidated affiliate, interest expense on commercial paper and interest expense on long-term debt. 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, 2004, 2003 and 2002.

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2004	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total

(In millions)

Operating revenues	$ 1,578.1	$ 3,443.9	$ ---	$ (95.4)	$ 4,926.6
Fuel	645.4	---	---	(49.5)	595.9
Purchased power	269.1	---	---	---	269.1
Gas and electricity purchased for resale (B)	---	3,054.3	---	(45.2)	3,009.1
Natural gas purchases - other	---	88.6	---	---	88.6
Cost of goods sold	914.5	3,142.9	---	(94.7)	3,962.7
Gross margin on revenues	663.6	301.0	---	(0.7)	963.9
Other operation and maintenance	301.9	101.5	(11.2)	---	392.2
Depreciation	122.7	47.6	8.3	---	178.6
Impairment of assets	---	7.8	---	---	7.8
Taxes other than income	47.0	17.5	3.3	---	67.8
Operating income (loss)	192.0	126.6	(0.4)	(0.7)	317.5
Other income	6.1	4.5	1.5	---	12.1
Other expense	(2.7)	(0.7)	(2.1)	---	(5.5)
Interest income	2.7	3.5	1.3	(2.3)	5.2
Interest expense	(37.5)	(37.5)	(23.4)	2.3	(96.1)
Income tax expense (benefit)	53.0	36.2	(8.7)	(0.3)	80.2
Income (loss) from continuing operations	107.6	60.2	(14.4)	(0.4)	153.0
Income from discontinued operations	---	0.5	---	---	0.5
Net income (loss)	$ 107.6	$ 60.7	$ (14.4)	$ (0.4)	$ 153.5
Total assets	$ 3,084.2	$ 1,807.7	$ 1,731.5	$ (1,753.1)	$ 4,870.3
Capital expenditures	$ 391.2	$ 32.1	$ 8.5	$ ---	$ 431.8

(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.

2004	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 326.8	$ 566.7	$ 3,056.1	$ (505.7)	$ 3,443.9
Operating income	$ 60.9	$ 56.2	$ 9.5	$ ---	$ 126.6

(B) OERI exited the power marketing business during the first quarter of 2004.

2003	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 1,517.1	$ 2,327.8	$ ---	$ (65.9)	$ 3,779.0

Fuel		544.5		---		---		(44.7)		499.8
Purchased power		292.9		---		---		---		292.9
Gas and electricity purchased for resale		---		2,019.1		---		(21.2)		1,997.9
Natural gas purchases - other		---		55.4		---		---		55.4
Cost of goods sold		837.4		2,074.5		---		(65.9)		2,846.0
Gross margin on revenues		679.7		253.3		---		---		933.0
Other operation and maintenance		294.8		91.2		(14.3)		---		371.7
Depreciation		121.8		44.2		10.9		---		176.9
Impairment of assets		---		9.2		1.0		---		10.2
Taxes other than income		46.9		17.5		2.9		---		67.3
Operating income (loss)		216.2		91.2		(0.5)		---		306.9
Other income		0.8		6.6		0.7		---		8.1
Other expense		(3.2)		(3.0)		(2.8)		---		(9.0)
Interest income		0.6		0.9		1.7		(1.9)		1.3
Interest expense		(38.8)		(39.8)		(21.3)		1.9		(98.0)
Income tax expense (benefit)		60.2		22.7		(9.2)		---		73.7
Income (loss) from continuing operations		115.4		33.2		(13.0)		---		135.6
Loss from discontinued operations		---		(0.4)		---		---		(0.4)
Income (loss) before cumulative effect of change in accounting principle		115.4		32.8		(13.0)		---		135.2
Cumulative effect on prior years of change in accounting principle, net of tax		---		(5.9)		0.5		---		(5.4)
Net income (loss)	$	115.4	$	26.9	$	(12.5)	$	---	$	129.8
Total assets	$	2,775.2	$	1,585.6	$	1,745.2	$	(1,521.3)	$	4,584.7
Capital expenditures	$	148.7	$	28.1	$	4.5	$	---	$	181.3

(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.

2003		Transportation and Storage		Gathering and Processing		Marketing		Eliminations		Total
(In millions)										
Operating revenues	$	249.0	$	512.0	$	1,964.0	$	(397.2)	$	2,327.8
Operating income	$	64.2	$	14.0	$	13.0	$	---	$	91.2

2002	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total

(In millions)

Operating revenues	$ 1,388.0	$ 1,684.0	$ ---	$ (48.1)	$ 3,023.9
Fuel	435.8	---	---	(33.6)	402.2
Purchased power	260.0	---	---	---	260.0
Gas and electricity purchased for resale	---	1,402.1	---	(14.5)	1,387.6
Natural gas purchases - other	---	70.5	---	---	70.5
Cost of goods sold	695.8	1,472.6	---	(48.1)	2,120.3
Gross margin on revenues	692.2	211.4	---	---	903.6
Other operation and maintenance	282.9	101.1	(14.0)	---	370.0
Depreciation	123.1	49.3	10.1	---	182.5
Impairment of assets	---	48.3	1.8	---	50.1
Taxes other than income	47.1	15.7	2.5	---	65.3
Operating income (loss)	239.1	(3.0)	(0.4)	---	235.7
Other income	0.7	1.5	1.5	---	3.7
Other expense	(3.1)	(0.6)	(1.0)	---	(4.7)
Interest income	1.2	1.1	19.1	(19.7)	1.7
Interest expense	(40.2)	(49.7)	(40.6)	19.7	(110.8)
Income tax expense (benefit)	71.6	(19.2)	(7.8)	---	44.6
Income (loss) from continuing operations	126.1	(31.5)	(13.6)	---	81.0
Income from discontinued operations	---	9.8	---	---	9.8
Net income (loss)	$ 126.1	$ (21.7)	$ (13.6)	$ ---	$ 90.8
Total assets	$ 2,659.9	$ 1,532.6	$ 1,820.3	$ (1,747.9)	$ 4,264.9
Capital expenditures	$ 198.7	$ 20.0	$ 14.8	$ 1.0	$ 234.5

(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.

2002	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 444.6	$ 179.0	$ 1,350.5	$ (290.1)	$ 1,684.0
Operating income (loss)	$ 45.6	$ (49.5)	$ 0.9	$ ---	$ (3.0)

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17. Commitments and Contingencies

Capital Expenditures

The Company s capital expenditures are estimated at approximately: 2005 $280.0 million, 2006 $250.9 million and 2007 $230.4 million.

Operating Lease Obligations

The Company has operating lease obligations expiring at various dates, primarily for OG&E railcar leases (expiring March 31, 2006) and Enogex noncancellable operating leases. Future minimum payments for noncancellable operating leases are as follows:

(In millions)		2005		2006		2007		2008		2009		2010 and Beyond
Operating lease obligations												
OG&E railcars (A)	$	5.4	$	5.4	$	5.3	$	5.4	$	5.3	$	24.9
Enogex noncancellable operating leases		3.7		3.2		0.9		0.1		0.1		0.1
Total operating lease obligations	$	9.1	$	8.6	$	6.2	$	5.5	$	5.4	$	25.0

(A) OG&E s current railcar operating lease expires March 31, 2006. OG&E expects to enter into a similar lease agreement for railcars at the expiration of the current lease. Therefore, comparable future minimum payments have been included in the table above.

Payments for operating lease obligations were approximately $9.7 million, $9.8 million and $10.6 million in 2004, 2003 and 2002, respectively.

OG&E Railcar Leases

At December 31, 2004, OG&E has a noncancellable operating lease which has 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. At the end of the lease term which is March 31, 2006, OG&E has the option to purchase the railcars at a stipulated fair market value. If OG&E chose not to purchase the railcars and the actual value of the railcars was less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to maximum of approximately $36 million. OG&E expects to enter into a new lease agreement for railcars effective April 1, 2006, which should negate any financial exposure under the current lease agreement. 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

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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.

During 2004, 2003 and 2002, OG&E made total payments to cogenerators of approximately $203.5 million, $203.0 million and $227.3 million, respectively, of which approximately $155.3 million, $164.7 million and $192.1 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: 2005 $99.5 million, 2006 $97.9 million, 2007 $96.3 million, 2008 $86.9 million and 2009 $85.0 million.

Fuel Minimum Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of approximately $166.5 million, $157.3 million and $164.1 million for the years ended December 31, 2004, 2003 and 2002, respectively. OG&E has entered into purchase commitments of necessary fuel supplies of approximately: 2005 $170.8 million, 2006 $160.0 million, 2007 $159.0 million, 2008 $164.8 million, 2009 $86.9 million and 2010 and Beyond $165.5 million.

OG&E has historically acquired some of its natural gas for boiler fuel under wellhead contracts that contain provisions allowing the owner to require prepayments for gas if certain minimum quantities are not taken. At December 31, 2004, approximately $21.0 million has been recorded in the Provision for Payments of Take or Pay Gas classified as Current Liabilities in the Consolidated Balance Sheet. At December 31, 2003, approximately $32.5 million has been recorded in the Provision for Payments of Take or Pay Gas classified as Deferred Credits and Other

Liabilities in the Consolidated Balance Sheet. These amounts represent OG&E s estimate of the maximum amount that it could be obligated to pay under certain take-or-pay contracts. OG&E believes that it is entitled to recover any such amounts from its customers through its regulatorily approved automatic fuel adjustment clauses or other regulatory mechanisms.

Natural Gas Units

In April 2004, OG&E utilized a request for bid (RFB) to acquire approximately 56 percent and 26 percent of its projected annual natural gas requirements for 2005 and 2006, respectively. All of these contracts are tied to various gas price market indices and most will expire in December 2006. Additional natural gas supply for the summer of 2005 will be secured through a new RFB issued in the first quarter of 2005. OG&E will meet additional natural gas requirements with monthly and daily purchases as required.

Natural Gas Storage Facility Agreement with Central Oklahoma Oil and Gas Corp.

In 1998, Enogex entered into a Storage Lease Agreement (the Agreement) with Central Oklahoma Oil and Gas Corp. (COOG). Under the Agreement, COOG agreed to make certain enhancements to the Stuart Storage Facility to increase capacity and deliverability of the facility. In 1999 a dispute arose as to whether the natural gas deliverability for the Stuart Storage Facility was

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being provided by COOG and these issues were submitted to arbitration in October and November 2001. In July 2002, the Oklahoma District Court affirmed the arbitration award and entered judgment against COOG and in favor of Enogex in the amount of approximately $23.3 million (the Judgment).

On July 24, 2002, Enogex exercised the asset purchase option provided in the Agreement and title to the Stuart Storage Facility was transferred to Enogex on October 24, 2002, effective August 9, 2002 (the date COOG turned over operations of the facility to Enogex). As part of the Agreement, the Company agreed in 1998 to make up to a $12 million secured loan to Natural Gas Storage Corporation (NGSC), an affiliate of COOG (the NGSC Loan). NGSC failed and refused to repay the NGSC Loan.

On August 12, 2002, the Company received a petition in a legal proceeding filed by COOG and NGSC against the Company and Enogex in Texas. COOG and NGSC stated a claim for declaratory judgment asserting, among other things, that NGSC is not obligated to make payments on the NGSC Loan based on various theories and, that: (1) the Company was obligated to demand Enogex make the requisite payments to the Company; (2) the Company is liable to NGSC for failing to demand the requisite payments from Enogex, or alternatively, NGSC is entitled to a reduction in the amount it owes to the Company; (3) Enogex was and is obligated to make the payments to the Company until the indebtedness of NGSC to the Company is reduced to zero; (4) Enogex is not entitled to set off the Judgment against the lease payments that it originally owed to COOG and now owes to the Company; (5) no event of default has occurred; and (6) under the Agreement, the only remedy Enogex had or has if the Stuart Storage Facility did not perform was to seek a modification of the lease payments based upon COOG s expert s analysis of the performance of the Stuart Storage Facility. COOG and NGSC have also stated claims for breach of contract relating to the same allegations in its claim for declaratory relief and include claims for attorneys fees.

The Company objected to being sued in Texas because the Texas Court does not have proper jurisdiction over the Company. In 2002, Enogex responded to the allegations, asserting, among other things, that the disputed issues have already been properly determined by the Arbitration Panel and the Oklahoma Court and, therefore, this action is improper.

By order dated June 19, 2003, the Texas Court granted Enogex s request for arbitration and ordered COOG, NGSC and Enogex to arbitration. The parties participated in the Oklahoma County arbitration in May 2004 and the arbitration panel rendered a decision in the Company s favor for approximately $5.0 million related to the outstanding NGSC Loan on July 15, 2004 and this judgment is final.

In 2003, the Company and Enogex brought separate complaints against the individual shareholders of COOG and NGSC Enogex Inc. v John C. Thrash, John F. Thrash and Robert R. Voorhees, Jr., Case No. CIV-03-0388-L; and OGE Energy Corp. and Enogex Inc. v John C. Thrash, John F. Thrash and Robert R. Voorhees, Jr., Case No. CIV 03-0389-L both filed in the Western District of Oklahoma Federal Court. The Company and Enogex each stated claims for (1) fraudulent transfer; (2) imposition of an equitable trust; and (3) breach of fiduciary duty. A jury trial was held from October 12 26, 2004. The case was submitted to the jury on October 25, 2004 and the jury ruled in favor of the Company and Enogex for approximately $6.6 million. The individual defendants have filed a motion for new trial, which is currently pending before the Court. Also in the Texas case, on October 4, 2004, the plaintiffs filed a first amended petition seeking: (i)

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declaratory judgment based on collusion to impair collateral; (ii) gross negligence; and (iii) declaratory judgment and confirmation of certain aspects of the arbitration award. The plaintiffs have added a request for punitive damages. A motion to strike the amended petition or alternatively refer any remaining issues to arbitration under the parties agreement has been filed by Enogex and the Company. The plaintiffs filed a motion to dismiss Enogex from the suit which the court granted by order dated January 26, 2005. Enogex has objected to this ruling and has requested reconsideration of the court s ruling to properly reserve the previous rulings in this matter. A determination relating to the jurisdiction by the Texas court of the Company is pending before the court.

The Company intends to continue to vigorously pursue its rights in conjunction with the remaining amounts owed under the judgments, plus interest.

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. Discovery is proceeding on limited jurisdictional issues as ordered by the Court. A hearing on the defendants motions to dismiss for lack of subject matter jurisdiction, including public disclosure, original source and voluntary disclosure requirements is set for March 17 18, 2005.

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The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, 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 at this time.

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. Discovery on class certification is proceeding. A hearing on class certification issues is set for April 1, 2005.

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, 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 at this time.

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. Discovery on class certification is proceeding. A hearing on class certification issues is set for April 1, 2005.

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, 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 at this time.

Agreement with Colorado Interstate Gas Company

In December 2002, Enogex entered into an agreement with Colorado Interstate Gas Company regarding reservation of firm capacity on an interstate gas pipeline that was initially proposed to be in service by August 31, 2005 (the Cheyenne Plains Pipeline). Under the final transportation agreement, OERI reserved 60,000 decatherms/day (Dth/day) of capacity on the pipeline for 10 years and two months. Such reservation provides OERI access to significant additional natural gas supplies in the Rocky Mountain production basins. The Cheyenne Plains Pipeline, which began full service in February 2005, provides interstate gas transportation services

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in Wyoming, Colorado and Kansas with a capacity of 560,000 Dth/day. OERI pays a demand fee of approximately $7.5 million annually for this capacity. Also, Enogex expects a loss of approximately $3.0 million in 2005 related to its Cheyenne Plains position as a result of unfavorable market conditions for the capacity primarily due to an earlier than expected in-service date for the project and the associated lack of upstream gas supply and pipeline infrastructure to deliver gas to the Cheyenne hub for 2005.

Guarantees

At December 31, 2004, 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 $8.2 million of collateral to satisfy its obligation under its financial and physical contracts.

Environmental Laws and Regulations

Approximately $7.0 million of the Company s capital expenditures budgeted for 2005 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 $57.8 million during 2005, compared to approximately $57.1 million in 2004. 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 January 24, 2005, national legislation was introduced in Congress that, if passed, could require a significant reduction in emissions of sulfur dioxide (SO2), nitrogen oxide (NOX) and mercury (Hg) from the electric utility industry. The legislation, introduced in Senate Bill 131, is commonly referred to as the Clear Skies Act of 2005.

While the United States has withdrawn its support of the Kyoto Protocol on global warming, legislation has been considered that would limit carbon dioxide (CO2) emissions. In 2004, the McCain-Lieberman Climate Change Bill addressed the reduction of CO2 as a means of addressing global warming; however, the bill was defeated in the Senate. President Bush supports voluntary reductions by industry. OG&E has joined other utilities in voluntary CO2 sequestration projects through reforestation of land in the southern United States. In addition, OG&E has committed to reduce its CO2 emission rate (lbs. CO2/megawatt-hour) by up to five percent over the next 10 years. However, if legislation is passed requiring mandatory reductions, this could have a tremendous impact on OG&E s operations by requiring OG&E to significantly reduce the use of coal as a fuel source.

Other potential air regulations also have emerged that could impact OG&E. On December 15, 2003, the Environmental Protection Agency (EPA) proposed regulations to limit mercury emissions from coal-fired boilers. This rule is expected to be finalized by early 2005. Earliest compliance by OG&E would be 2008. Depending upon the final regulations, this could result in significant capital and operating expenditures. In addition, on January 30, 2004, the EPA proposed a Clean Air Interstate Rule. This rule is intended to control SO2 and NOX from utility boilers in order to minimize the interstate transport of air pollution. The State of Oklahoma, however, is not listed as one of the states affected by the proposed rule. This, however, could change as the EPA has indicated its intentions to review Oklahoma s impact on other states. If Oklahoma is included in the final rule reductions, this could lead to significant capital and operating expenditures by OG&E.

In 1997, the EPA finalized revisions to the ambient ozone and fine particulate standards. After a court challenge, which delayed implementation, the EPA has now begun to finalize the implementation process. Based on the most recent monitoring data, the EPA has designated Oklahoma in attainment with both standards. However, both Tulsa and Oklahoma City had previously entered into an Early Action Compact with the EPA whereby voluntary measures will be enacted to reduce ozone. In order to ensure that ozone levels remain below the standards, both cities intend to comply with the compact. Minimal impact on OG&E s operations is expected.

In 1999, the EPA first issued regulations concerning regional haze. These regulations are intended to protect visibility in national parks and wilderness areas throughout the United States. In Oklahoma, the Wichita Mountains would be 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 the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas. This study will be complete and any compliance strategies adopted by January 2008. If an impact is determined, then significant capital expenditures could be required for both the Sooner and Muskogee generating stations.

As required by Title IV of the Clean Air Act Amendments of 1990 (CAAA), OG&E completed installation and certification of all required continuous emissions monitors at its generating stations in 1995. Since then, OG&E has submitted emissions data quarterly to the EPA as required by the CAAA. Beginning in 2000, OG&E became subject to more stringent SO2 emission requirements (Phase II of the CAAA). These lower limits had no significant financial impact due to OG&E s earlier decision to burn low sulfur coal. In 2004, OG&E s SO2 emissions were well below the allowable limits.

The 1990 Clean Air Act includes an emission reduction program to reduce SO2 emissions. Reductions were obtained through a program of emission (release) allowances issued by the EPA to power plants covered by the acid rain program. Each allowance is worth one ton of SO2 released from the smokestack. Plants may only release as much SO2 as they have allowances. Allowances may be banked and traded or sold nationwide. The EPA allocated sulfer dioxide allowances to OG&E starting in 2000 and OG&E started banking allowances in 2001. At December 31, 2004, OG&E has banked approximately 31,784 allowances. In light of emerging regulations with uncertain outcomes, OG&E s current strategy for management of the allowances is to bank them for future use.

With respect to the NOX regulations of Title IV of the CAAA, 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 2004 were 0.337 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, among other things, legislation is enacted, a study currently being conducted by the state of Oklahoma determines that such NOX emissions are contributing to regional haze and 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 Oklahoma Department of Environmental Quality s (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, 2004, 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 2004. The fees for 2005 are estimated to be approximately the same as in 2004.

The ODEQ is expected to adopt a new regulation dealing with the emission of toxic air contaminants. While it is unknown at this time what impact, if any, this rule will have on OG&E, the rule s impact could be significant if the ODEQ identifies high concentrations of any toxic contaminants near OG&E facilities.

The EPA continues to investigate and enforce against electric utilities around the country for alleged violation of its New Source Review regulations. While OG&E believes it has complied with all regulations, it appears that the EPA will begin investigating electric utilities in Oklahoma and surrounding states in 2005.

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 2004, OG&E obtained refunds of approximately $0.8 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 submitted one application during 2004 to renew an Oklahoma Pollutant Discharge Elimination System (OPDES) permit. OG&E has received three renewed wastewater permits during 2004. All permits received to date have been reasonable in their requirements, allow operational flexibility and provide reductions in operating costs.

OG&E requested, based on the performance of a site-specific study, that the state agency responsible for the development of water quality standards adjust the in-stream copper criterion at one of our facilities. The state and the EPA have approved the new in-stream criteria for copper thereby avoiding costly treatment and/or facility reconfiguration requirements. Based on this approval, an OPDES permit was issued during 2004 for the facility that contains no copper limitations.

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. New EPA 316(b) rules for existing facilities became effective July 23, 2004. OG&E has acquired the services of a consultant to assist in the development of Proposal for Information Collection documents for four applicable facilities. These documents will be submitted to the state regulatory agency for review and approval during the first or second quarters of 2005. Depending on the analysis of these final 316(b) rules, capital and/or operating costs may increase at some of OG&E s generating facilities.

Enogex

The construction and operation of pipelines, plants and other facilities for gathering, processing, treating, transporting 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 clean up hazardous substances at the locations at which 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 as to future compliance. Enogex generates 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 to be towards stricter 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. Management consults with 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. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently 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. This assessment of currently pending or threatened lawsuits is subject to change.

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, 2004, 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.

Recent Regulatory Matters

2002 Settlement Agreement

On November 22, 2002, the OCC signed a rate order containing the provisions of a Settlement Agreement of OG&E s rate case. The Settlement Agreement provides 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 MWs (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 off-system sales. Previously, OG&E had a 50/50 sharing mechanism in Oklahoma for any off-system sales. The 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 of 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. If any of the $5.4 million is not recovered at the end of the three years, the OCC will authorize the recovery of any remaining costs. During the year ended December 31, 2004, OG&E recovered approximately $1.8 million in annual net profits from off-system sales, gave 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.

OCC Order Confirming Savings

The 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

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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 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 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 has appealed the OCC s order to the Oklahoma Supreme Court. OG&E currently believes that the appeal is without merit.

Recent Acquisition of Power Plant

On August 18, 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC s 77 percent interest in the McClain Plant. The acquisition of this 77 percent interest was intended to satisfy the requirement in the Settlement Agreement to acquire New Generation. The McClain Plant includes natural gas-fired combined cycle combustion turbine units and is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority (OMPA).

OG&E completed the acquisition of the McClain Plant on July 9, 2004. The purchase price for the interest in the McClain Plant was approximately $160.0 million. The closing was subject to customary conditions including receipt of certain regulatory approvals. Because NRG McClain LLC had filed for bankruptcy protection, the acquisition was subject to approval by the bankruptcy court. As part of the bankruptcy approval process, NRG McClain LLC s interest in the plant was subject to an auction process and on October 28, 2003, the bankruptcy court approved the sale of NRG McClain LLC s interest in the plant to OG&E.

The final approval OG&E had been waiting for was the approval from the FERC. On July 2, 2004, the FERC authorized OG&E to acquire the McClain Plant. The FERC s approval was based on an offer of settlement OG&E filed in a proceeding on March 8, 2004. Under the offer of settlement, OG&E proposed, among other things, to install certain new transmission facilities and to hire an independent market monitor to oversee OG&E s activity for a limited period. Two other parties, InterGen Services, Inc. and AES Shady Point, opposed OG&E s offer of settlement and filed competing settlement offers. In the July 2, 2004 order, the FERC: (i) approved OG&E s offer of settlement subject to conditions; (ii) rejected the competing offers of settlement; and (iii) approved OG&E s acquisition of the McClain Plant. As part of the July 2, 2004 order, OG&E agreed to undertake the following mitigation measures: (i) install a transformer at one of its facilities at a cost of approximately $9.3 million which was completed in the fourth quarter of 2004; (ii) provide a 600 MW bridge into its control area from the Redbud Energy LP (Redbud) plant; and (iii) hire an independent market monitor to oversee OG&E s activity in its control area. The market monitoring plan is designed to detect any anticompetitive conduct by OG&E from operation of its generation resources or its transmission system. The market monitoring function is performed daily and periodic reviews are also performed. To date, the independent market monitor has filed two reports, one on October 13, 2004 covering the period from July 10, 2004 to September 30,

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2004, and one on January 14, 2005 covering the period from October 1, 2004 to December 31, 2004. Based on an analysis of transmission congestion data on OG&E s system, along with data on purchases and sales, generation dispatch data and power flows on OG&E s tie lines, the market monitor concluded that OG&E did not act in an anticompetitive manner through either dispatch of its generation or operation of its transmission system. Additionally, OG&E s operations under the ongoing mitigation measures that require OG&E to make available transmission capability available to the Redbud power plant for access to the OG&E system were analyzed. Based on this analysis, the market monitor concluded that OG&E has complied with this requirement. Further, in the review of the disposition of requests for transmission service, the independent market monitor detected no problems with access to OG&E s transmission system. OG&E expects to complete the installation and implementation of these measures by June 2005. One party has filed a request for rehearing of the FERC s July 2, 2004 order. The outcome of that request for rehearing cannot be determined at this time.

OG&E is operating the plant in accordance with a joint ownership and operating agreement with the OMPA. Under this agreement, OG&E operates the facility, and OG&E and the OMPA are entitled to the net available output of the plant based on their respective ownership percentages. All fixed and variable costs, except fuel and gas transportation costs, are shared in proportion to the respective ownership interests. Fuel and gas transportation costs are paid in accordance with each individual owner s respective transportation contract and consumption. OG&E expects to utilize its portion of the output, 400 MWs, to serve its native load. As a result, OG&E expects to file with the OCC a request to increase its rates to its Oklahoma customers to recover, among other things, its investment in, and the operating expenses of, the McClain Plant no later than July 8, 2005. OG&E expects to file a rate case during the second quarter of 2005 using 2004 as a test year with new approved rates expected to be in effect by January 2006. As provided in the Settlement Agreement, until OG&E seeks and obtains approval of a request to increase base rates to recover, among other things, the investment in the plant, OG&E will have 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. If the OCC were to approve OG&E s request, all prudently incurred costs accrued through the regulatory asset within the 12-month period would be included in OG&E s prospective cost of service and would be recovered over a period to be determined by the OCC.

OG&E temporarily funded the McClain Plant acquisition with short-term borrowings from the Company. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings. Also, on August 9, 2004, the Company made a capital contribution to OG&E of approximately $153.0 million.

OG&E expects the acquisition 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, in excess of $75.0 million to its Oklahoma customers. These savings will be derived from: (i) the avoidance of purchase power contracts otherwise needed; (ii) an above market cogeneration contract with PowerSmith Cogeneration Project, L.P. (PowerSmith) when it terminated at the end of August 2004; and (iii) fuel savings associated with operating efficiencies of the new plant. These savings, while providing real savings to Oklahoma customers, are not expected to affect OG&E s profitability because its rates are not expected to be reduced to accomplish these savings. In the event OG&E is unable to demonstrate at least $75.0 million in savings to its customers during this

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36-month period, OG&E will be required to credit its Oklahoma customers any unrealized savings below $75.0 million as determined at the end of the 36-month period ending December 31, 2006. At this time, OG&E believes that it will be able to demonstrate at least $75.0 million in savings during this period.

Contract with PowerSmith

In September 2003, PowerSmith filed an application with the OCC seeking to compel OG&E to continue purchasing power from PowerSmith s qualified cogeneration facility under the Public Utility Regulatory Policy Act of 1978 at a price that would include an avoided capacity charge equal to the avoided cost of the McClain Plant. On June 7, 2004, OG&E and PowerSmith signed a 15-year power sales agreement under which OG&E would contract to purchase electric power from PowerSmith. On August 27, 2004, the new 15-year power sales agreement was approved by the OCC and became effective September 1, 2004. OG&E s ability to meet its guarantee of customer savings of at least $75 million over three years is not expected to be materially affected by this new agreement to purchase electric power from PowerSmith.

FERC Section 311 2001 and 2004 Rate Cases and related FERC dockets

In December 2001, Enogex made a filing at the FERC under Section 311 of the Natural Gas Policy Act to establish rates, to establish a default processing fee and to address various other issues for the combined Enogex and Transok L.L.C. pipeline systems. In May 2003, the FERC accepted a stipulation and settlement agreement and entered an order modifying Enogex s SOC with respect to priority for dedicated gas. The settlement included a fee to be assessed under certain market conditions to process customer gas gathered behind processing plants so that it meets the heating value standards of natural gas transmission pipelines (default processing fee). This default processing fee, which decreases the volatility of Enogex s earnings stream by reducing Enogex s exposure to keep-whole processing arrangements, is implemented in the event the natural gas liquids revenue less the associated fuel and shrinkage costs is negative. Pursuant to Enogex s SOC that was effective through September 30, 2004, if Enogex s annual processing gross margin exceeds a specified threshold, Enogex is 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.

During the third and fourth quarters of 2003, the Company established approximately a $4.9 million reserve to cover such refund obligations. During April 2004, the Company refunded its default processing fee refund obligation under the SOC to the applicable customers. For the year ended December 31, 2004, the Company billed default processing fees of approximately $0.2 million, which has been recorded as deferred revenue. For the year ended December 31, 2003, the Company recorded net default processing fee revenue, that is, net of the $4.9 million reserve discussed above, of approximately $0.3 million. The Company records any default processing fees billed to customers as deferred revenue until it becomes probable that the processing gross margin threshold in Enogex s SOC will not be exceeded. Based on the 2004 processing gross margin, the default processing fees billed to customers in 2004 were recorded as deferred revenue as the 2004 processing gross margin exceeded the 2004 processing gross margin threshold in the SOC. During April 2005, the Company expects to refund its 2004 default processing fee refund obligation under the SOC to the applicable customers. Also, during the years ended December 31, 2004 and 2003, respectively, the Company recognized revenue of approximately $0.5 million and $0.7 million of low flow meter charges.

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. Thereafter, the FERC will regulate Enogex s Section 311 transportation and any regulation of gathering will be pursuant to Oklahoma statute. Several parties challenged the SOC changes and the filing is currently under review at the FERC. On September 30, 2004, Enogex made a filing at the FERC to update Enogex s Section 311 maximum transportation rate. Certain parties challenged aspects of the rate filing. In addition, on September 29, 2004, Enogex filed an updated fuel factor with the FERC for the last quarter of 2004. One party protested the fourth quarter 2004 fuel filing. The FERC Staff served data requests concerning the revised SOC, the rate filing, and the fourth quarter 2004 fuel filing on December 3, 2004. An initial technical conference in these dockets was held on January 13, 2005. At the conference, the parties agreed to brief one aspect of the Enogex filing now and to seek an extension of time for resolution of the filing in which to attempt to settle the rate case. Enogex and nearly all of the intervening parties filed a joint unopposed motion for an extension of time on January 25, 2005. Enogex and certain intervenors filed individual initial comments on January 26, 2005 and reply comments on February 2, 2005 seeking policy guidance from the FERC. The FERC has not yet acted on either the motion or the comments.

Finally, on November 15, 2004, Enogex filed an updated fuel factor for fuel year 2005 (calendar year 2005)**.** The filing is the annual filing made by Enogex that establishes the fixed fuel percentage for natural gas shipped on the Enogex system. One intervenor has challenged the annual fuel factor filing. There has been no discovery or FERC action on this annual fuel filing and the timing of such action is uncertain.

Security Enhancements

On April 8, 2002, OG&E filed a joint application with the OCC requesting approval for security investments and a rider to recover these costs from the ratepayers. On August 14, 2002, OG&E filed testimony with the OCC outlining proposed expenditures and related actions for security enhancement and a proposed recovery rider. Attempting to make security investments at the proper level, OG&E has developed a set of guidelines intended to minimize long-term or widespread outages, minimize the impact on critical national defense and related customers, maximize the ability to respond to and recover from an attack, minimize the financial impact on OG&E that might be caused by an attack and accomplish these efforts with minimal impact on ratepayers. The OCC Staff retained a security expert to review the report filed by OG&E. On July 13, 2004, the security expert filed testimony that recommended: (i) $19.0 million in capital expenditures and $2.5 million annually in operating and maintenance expenses are justified to enhance the security of OG&E s infrastructure; and (ii) a security rider should be authorized to recover costs as these projects are completed. On August 4, 2004, OG&E filed responsive testimony that quantified the minimal customer impact and revised its request for security investments so that it was consistent with the OCC Staff s recommendations. On August 13, 2004, the only intervening party, the Oklahoma Industrial Energy Consumers (OIEC), filed a statement of position which supported the OCC Staff s recommendations. 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. The hearing in this case was held on November 9, 2004, at which time the administrative law judge approved the stipulation agreement between all parties. On December 21, 2004 the OCC issued an order approving the security rider.

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On October 17, 2003, the OCC filed a notice of inquiry to consider the issues related to the role of the OCC and Oklahoma regulated companies in addressing the security of the utility system infrastructure and key assets. On March 4, 2004, the OCC deliberated the notice of inquiry and directed the OCC Staff to file a rulemaking proceeding for each utility industry regarding security of the utility system infrastructure and key assets. On August 27, 2004, the OCC Staff filed a Notice of Proposed Rulemaking. The first technical conference was held on September 23, 2004 and written comments were filed by all the parties on October 1, 2004. A second technical conference was held on October 21, 2004. The hearing in this case was held on December 3, 2004. On December 10, 2004, the OCC submitted the amended rules to the Governor s Office and Oklahoma Legislature.

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 would reduce 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 current cogeneration credit rider expired December 31, 2004. On October 29, 2004, the OCC Staff and other parties filed responsive testimony. Hearings in this case were held on November 15, 2004, at which time the administrative law judge recommended approval of the proposed cogeneration credit rider. On December 21, 2004 the OCC issued an order approving the new cogeneration credit rider which will lower electric bills by approximately $80 million annually.

Pending Regulatory Matters

Currently, OG&E has one significant matter pending at the OCC which is a review of the process completed by OG&E in its selection of gas transportation and storage services to meet its system operating needs. This matter, as well as several other matters pending before the FERC, are discussed below.

Gas Transportation and Storage Agreement

As part of the 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 Settlement Agreement. The prescribed bidding process detailed in the Settlement Agreement provided that each generation facility seek bids separately for the services required. OG&E believes that in order for it to achieve maximum coal generation, which delivers the lowest cost energy to its customers, and ensure reliable electric service, it must have integrated, firm no-notice load following service for both gas transportation and gas storage. This type of service is required to satisfy the daily swings in customer demand placed on OG&E s system and still permit natural gas units to not impede coal energy production. OG&E also believes that gas storage is an integral part of providing gas supply to OG&E s generation facilities. Accordingly, OG&E evaluated its competitive bid options in light of these circumstances. OG&E s evaluation clearly demonstrates that the Enogex integrated gas system provides superior integrated, firm no-notice load following service to OG&E that is not available from other companies serving the OG&E marketplace.

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On April 29, 2003, as required by the Settlement Agreement, OG&E filed an application with the OCC in which 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 loss and unaccounted for gas on the transportation system. To the extent OG&E transports gas in quantities in excess of the prescribed MDQs or MHQs, it pays an overrun service charge. During the years ended December 31, 2004, 2003 and 2002, OG&E paid Enogex approximately $49.6 million, $44.7 million and $36.9 million, respectively, for gas transportation and storage services.

Based upon requests for information from intervenors, OG&E requested from Enogex and Enogex retained a cost of service consultant to assist in the preparation of testimony related to this case. On March 31, 2004, OG&E filed testimony and exhibits with the OCC, which completed the initial documentation required to be filed in this case. On July 12, 2004, 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 to recover the $46.8 million annual demand fee requested, which results in no refund, and also recommended that OG&E provide at its next general rate review the results of an open competitive bidding process or a comprehensive market study. If OG&E does not provide such open bidding or market study, the OCC Staff recommendation would cap recovery at approximately $40 million at OG&E s next general rate review. The recommendations in the testimony of the Attorney General s office and the OIEC would cap recovery at approximately $35 million and $30 million, respectively, with the difference between what OG&E has been collecting through its automatic fuel adjustment clause and these recommended amounts being refunded to customers.

OG&E filed rebuttal testimony on August 16, 2004 in this case. Hearings in this case before an administrative law judge occurred from September 16-22, 2004. On October 22, 2004, the administrative law judge overseeing the proceeding recommended approximately $41.9 million annual demand fee recovery with OG&E refunding to its customers any demand fees collected in excess of this amount. If this recommendation is ultimately accepted, OG&E believes its refund obligation would be approximately $6.9 million at December 31, 2004, which the Company does not believe is material in light of previously established reserves. OG&E believes the amount currently paid to Enogex for integrated, firm no-notice load following transportation and storage services is fair, just and reasonable. OG&E and other parties to the proceeding appealed the administrative law judge s recommendation on November 1, 2004 and a hearing in this case was held before the OCC on December 7, 2004. The OCC took the case under advisement and an OCC order in the case is expected in the first quarter of 2005. There can be no guarantee that the OCC will approve the $41.9 million annual demand fee recovery recommended by the administrative law judge.

Southwest Power Pool

OG&E is a member of the Southwest Power Pool (SPP), the regional reliability organization for all or parts of Oklahoma, Arkansas, Kansas, Louisiana, New Mexico, Mississippi,

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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 a regional transmission organization (RTO). On February 10, 2004, the FERC conditionally approved the SPP s application. The SPP must meet certain conditions before it may commence operations as an RTO. On April 27, 2004, the SPP Board of Directors took actions to meet the conditions to satisfy the FERC requirement for formal approval of the RTO. The SPP compliance filing at the FERC was made on May 3, 2004. In response to a subsequent FERC order on July 2, 2004, the SPP made a compliance filing on August 6, 2004 stating that all requirements had been met to achieve RTO status. In a FERC order dated October 1, 2004, the FERC accepted the SPP s compliance filing and the SPP was granted RTO status, subject to the SPP submitting a further compliance filing, within 30 days. On November 1, 2004, the SPP made a compliance filing as required under the October 1 FERC order. Also, on November 1, the SPP filed a request for rehearing of the FERC s October 1 order. On December 1, 2004, the FERC granted the request for rehearing. 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 recent approval of the SPP RTO application is not expected to significantly impact the Company s consolidated financial results.

Currently, the regional state committee, which is comprised of commissioners regulating the state regulatory jurisdictional SPP members, is in the process of formulating a methodology for funding transmission expansion in the SPP s control area by allocating costs of transmission expansion to the SPP members who benefit. The SPP plans to make a filing at the FERC in February 2005 related to this matter. Also, the SPP is in the process of developing a process, required by the FERC, to create an imbalance energy market which will require cash settlements for over or under generation. Each SPP member will be responsible for monitoring its generation in its control area on an hourly basis and periodically submitting this information to the SPP, who will then provide settlement statements to each of the SPP members. The imbalance energy market requirements are planned to be effective October 1, 2005.

FERC Standards of Conduct

On November 25, 2003, the FERC issued new rules regulating the relationships between electric and natural gas transmission providers, as defined in the rules, and those entities merchant personnel and energy affiliates. The new rules will replace the existing rules governing these relationships. The new rules expand the definition of affiliate and further limit communications between transmission providers and those entities merchant personnel and energy affiliates.

In February 2004, OG&E and Enogex submitted plans and schedules to the FERC which detail the necessary actions to be in compliance with these new rules and expected that their initial costs to comply with the final rules would not exceed $1.6 million in 2004. On April 16, August 2 and December 21, 2004, the FERC issued orders on rehearing in which the FERC largely rejected requests to revise its November 25, 2003 final rule. However, the FERC did extend the compliance date until September 22, 2004 and did clarify certain aspects of the rule.

On September 21, 2004, Ozark filed a request for clarification of the FERC s Order 2004 regulations to permit Ozark to share a common gas control group with its energy affiliates. Granting the request would eliminate the need for Ozark to establish a separate gas control group. On November 26, 2004, the FERC granted Ozark s request.

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OG&E and Enogex believe that they have taken the necessary actions to comply with the new rules. The initial cost of compliance incurred in 2004 was less than $0.5 million. Additionally, OG&E and Enogex believe that the recurring cost of compliance in future years will be immaterial to OGE Energy Corp.

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 April 14, 2004, the FERC issued: (1) interim requirements for the FERC jurisdictional electric utilities who have been granted authority to make wholesale sales at market-based rates; and (2) an order initiating a new rulemaking on future market-based rates authorizations. The interim method for analyzing generation market power requires two assessments whether the utility is a pivotal supplier based on a control area s annual peak demand and whether the utility exceeds certain market share thresholds on a seasonal basis. If an applicant fails to pass either assessment, the FERC will presume that the utility can exercise generation market power and will initiate an investigation into the scope of the applicant s market power. The FERC will allow a utility to rebut that presumption through the submission of additional information. If an applicant is found to have generation market power, the applicant must propose a market power mitigation plan. The new interim assessment methods are applicable to all pending initial market-based rate applications and triennial reviews pending the rulemaking described below. 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 two interim tests described above. In the rulemaking proceeding, the FERC is seeking comments on the adequacy of the FERC s current analysis of market-based rate filings, including the adequacy of the new interim assessment of generation market power. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 which shows the impact of the new requirements on OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but failed to pass the market share screen. OG&E and OERI provided an explanation as to why its failure of the market share screen should not be viewed as an indication that they can exercise generation market power. OG&E and OERI do not know when the FERC will act on the filing or what action the FERC will take.

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.

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Redbud Tariff Filing

On March 5, 2004, Redbud filed a rate schedule with the FERC in Docket No. ER04-622-000 under which Redbud proposed to charge OG&E a rate for transmission service Redbud alleges it provides to OG&E over certain facilities that Redbud constructed to connect its generation facility to the OG&E transmission grid. Redbud claims that the facilities cost approximately $19.3 million, and seeks to recover this amount from OG&E over a 60-month period. Also on March 5, 2004, Redbud filed an application with the FERC in Docket No. EG04-38-000 asking the FERC to rule that Redbud can charge OG&E this fee for transmission service and remain an exempt wholesale generator under Section 32 of the Public Utility Holding Company Act of 1935. OG&E opposed Redbud s filings in the two dockets on the grounds that Redbud is not entitled to impose such a transmission rate, and that the imposition of such a rate is inconsistent with Redbud s status as an exempt wholesale generator. On May 4, 2004, the FERC issued an order rejecting Redbud s proposed rate schedule. Redbud has since asked the FERC to rehear and reverse its May 4 order rejecting Redbud s filing. On November 1, 2004, the FERC issued an order denying Redbud s request for rehearing. Redbud had 60 days to file a petition for review with the FERC. Redbud did not file a petition for review with the FERC and this case is now considered closed.

National Energy Legislation

In December 2004, the 108th Congress concluded without enactment of a comprehensive energy bill that had been debated in the Senate and the House of Representatives during 2003 and 2004. While the House had given strong support to the bill, the Senate failed to overcome a filibuster which blocked final passage. The bill, as it came out of the House-Senate conference, would have been largely beneficial to the Company. It contained provisions that would have minimized the risk of future uneconomic purchased power contracts being forced on the Company under PURPA, and provided tax incentives for investment in the electric transmission and natural gas pipeline systems. The bill also provided favorable provisions for mandatory reliability regulation by the North American Electric Reliability Council with oversight by the FERC, and contained improved FERC siting authority for construction of electric transmission in disputed areas. Also deemed positive by the Company was the fact that the bill did not contain any provisions for federal mandates of renewable energy which would have had the effect of raising the Company s electric rates. Another significant provision of the energy bill was the repeal of the Public Utility Holding Company Act of 1935 which was of minimal impact to the Company.

While Congress did not enact the comprehensive energy bill in 2004, Congress was able to pass some elements of that comprehensive bill as parts of other legislation. In particular, in the Foreign Sales Corporation Extra-Territorial Income bill, Congress enacted some provisions relating to the reauthorization of the expired tax credits for renewable energy projects, including wind turbines, and permitted utilities to deduct a percentage of their generation revenue as manufacturers of energy.

Looking to the 109th Congress in 2005, the Republican congressional leadership and the Bush Administration have indicated that enactment of a comprehensive energy bill remains a priority. While the precise contours of that legislation to be considered in 2005 remain unknown at this time, many observers anticipate that a bill basically following the substance of the energy bill that was nearly passed in the 108th Congress, with some modifications, will serve as the vehicle.

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Federal law imposes numerous responsibilities and requirements on OG&E. PURPA requires electric utilities, such as OG&E, to purchase power generated in a manufacturing process from a QF. Generally stated, electric utilities must purchase electric energy and production capacity made available by QFs at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and production capacity from these sources rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers. OG&E has entered into agreements with four such cogenerators. Electric utilities also must furnish electric energy on a non-discriminatory basis at a rate that is just, reasonable and in the public interest and must provide certain types of service which may be requested by QFs to supplement or back up those facilities own generation.

Although efforts to increase competition at the state level have been stalled, there have been several initiatives implemented at the federal level to increase competition in the wholesale markets for electricity. The National Energy Policy Act of 1992 (Energy Act), among other things, promoted the development of independent power producers (IPP). The Energy Act was followed by FERC Order 888 and Order 889, which facilitated third-party utilization of the transmission grid for sales of wholesale power. The Energy Act, Orders 888 and 889, and other FERC policies and initiatives have significantly increased competition in the wholesale power market. Utilities, including OG&E, have increased their own in-house wholesale marketing efforts and the number of entities with whom they historically traded. While power marketers became an increasingly important presence in the industry, their importance has declined following the bankruptcy of Enron and the financial troubles of other significant power marketers. These entities typically arbitrage wholesale price differentials by buying power produced by others in one market and selling it in another. IPPs also are becoming a more significant sector of the electric utility industry. In both Oklahoma and Arkansas, significant additions of new power plants have been announced and, in some cases completed, almost all of it from IPPs.

Notwithstanding these developments in the wholesale power market, the FERC recognized that impediments remained to the achievement of fully competitive wholesale markets including: (i) engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid; and (ii) continuing opportunities for transmission owners (primarily electric utilities) to discriminate in the operation of their transmission facilities in favor of their own or affiliated power marketing activities. In the past, the FERC only encouraged utilities to join and place their transmission systems under the operational control of independent system operators. On December 20, 1999, the FERC issued Order 2000, its final rule on RTOs. Order 2000 is intended to have the effect of turning the nation s transmission facilities into independently operated common carriers that offer comparable service to all would-be-users. Although adopting a voluntary approach towards RTO formation, the FERC stressed that Order 2000 does not preclude it from requiring RTO participation. Order 2000 set out a timetable for every jurisdictional utility (including OG&E) to either join in an RTO filing, or, alternatively, to submit a filing describing its efforts to join an RTO, the reasons for not participating in an RTO proposal and any obstacles to participation, and its plans for further work toward participation. In October 2004, the FERC gave its approval to the creation of the SPP RTO, of which OG&E is a member.

In July 2002, the FERC issued a Notice of Proposed Rulemaking on Standard Market Design Rulemaking for regulated utilities. If implemented as proposed, the rulemaking will substantially change how wholesale electric markets operate throughout the United States. The proposed rulemaking expands the FERC s intent to unbundle transmission operations from integrated utilities and ensure robust competition in wholesale markets. The proposed rule

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contemplates that all wholesale and retail customers will take transmission service under a single network transmission service tariff. The rule also contemplates the implementation of a bid-based system for buying and selling energy in wholesale markets. RTOs or Independent Transmission Providers will administer the market. RTOs will also be responsible for regional plans that identify opportunities to construct new transmission, generation or demand side programs to reduce transmission constraints and meet regional energy requirements. Finally, the rule envisions the development of Regional Market Monitors responsible for ensuring the individual participants do not exercise unlawful market power. On April 28, 2003, the FERC issued a White Paper, Wholesale Market Platform , in which the FERC indicated that it will change the proposed rule as reflected in the White Paper and following additional regional technical conferences. The FERC committed in the White Paper to work with interested parties including state commissions to find solutions that will recognize regional differences within regions subject to the FERC s jurisdiction. Thus far, the FERC has held conferences in Boston, Omaha, Wilmington, Tallahassee, Phoenix, New York, Dallas, Atlanta and San Francisco.

On April 14, 2004, the FERC initiated Docket No. RM04-7 to review its generation market power screening processes. The existing four-prong test was developed over 15 years in what the FERC characterizes as a different marketplace than today. The FERC plans to review the continued appropriateness of the four-prong test and consider amendments and additions to the required tests. On May 11, 2004, the FERC opened Docket No. PL04-6 establishing an investigation of best practices for competitive solicitation methods for public utilities, including public utility sales to affiliates. The purpose of this investigation is to ensure that transactions filed with the FERC are the result of a fair and open procedure. On October 6, 2004, the FERC established Docket No. RM04-14 to set guidelines for events that would trigger a reporting obligation on the part of any public utility with the authority to engage in sales for resale of electric energy in interstate commerce at market-based rates and possibly modify the market-based rate authority for public utilities that had a qualifying change in status that would affect their relevant market power. On February 10, 2005, the FERC issued Order 652 related to Docket RM04-14. The Company is currently evaluating Order 652 to determine the impact on the Company. Although technical conferences have been held for the first two of these dockets, to date no definitive rules or guidance have been issued by the FERC. Dockets RM04-7 and PL04-6 remain open. Any of these dockets may have a material effect upon the Company s participation in wholesale energy markets.

In October 2003, the FERC issued new rules governing corporate money pools, which include jurisdictional public utility or pipeline subsidiaries of nonregulated parent companies. The rules require documentation of transactions within such money pools and notification to the FERC if the common equity ratio of the utility falls below 30 percent.

The FERC requires all utilities authorized to sell power at market-based rates to file updated market power analyses every three years. In December 2003, OG&E filed its updated market power analysis with the FERC.

State Legislative Initiatives

Oklahoma

As previously reported, the Oklahoma legislature originally adopted the Electric Restructuring Act of 1997 (the 1997 Act) to provide retail customers in Oklahoma with a choice of their electric supplier. The scheduled start date for customer choice has been indefinitely

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postponed. In the 2003 legislative session, attempts to repeal the 1997 Act were initiated, but the session ended without repeal of the 1997 Act. It is unknown at this time whether the 1997 Act will be repealed.

In the 2004 legislative session, legislation was enacted requiring a study to determine the feasibility of providing investor-owned utilities an incentive to enter into purchase power agreements in Oklahoma by allowing the utilities to earn a return on purchased power. The study committee held its first meeting in August and continued holding two meetings a month through November. At the conclusion of the meetings, the study committee determined that the final report would make no recommendations to the legislature in January 2005.

During the 2004 legislative session, the Oklahoma state legislature passed a bill amending the Oklahoma Gas Gathering Act (the Gathering Act) and the Governor signed the bill into law in April 2004. Previously, Oklahoma law established a complaint procedure by which producers of natural gas could file a complaint with the OCC, asserting that a gatherer s proposed fees or terms and conditions of service were unfair or discriminatory, and request that the OCC set the fee or terms. The amendments to the Gathering Act maintained the complaint driven form of regulation by the OCC, but modified certain procedural aspects by which the complaint is handled. In particular, the amendments relate to the discovery process, and the OCC s ability to require parties and non-parties to produce documents and contracts related to the complaint at issue. However, under the amendments, processing natural gas remains unregulated. Additionally, the amendments do not allow the OCC to abrogate existing contracts between producers and gatherers.

Arkansas

In April 1999, Arkansas passed the Restructuring Law calling for restructuring of the electric utility industry at the retail level. The Restructuring Law, which had initially targeted customer choice of electricity providers by January 1, 2002, was repealed in March 2003 before it was implemented. As part of the repeal legislation, electric public utilities were permitted to recover transition costs. OG&E incurred approximately $2.4 million in transition costs necessary to carry out its responsibilities associated with efforts to implement retail open access. On January 20, 2004, the APSC issued an order which authorized OG&E to recover approximately $1.9 million in transition costs over an 18-month period beginning February 2004.

In the 2003 legislative session, legislation was enacted requiring a study relating to the restructuring of the electric utility industry at the industrial level to provide customer choice of electricity providers for large customers. A roundtable discussion regarding the study was held on July 22, 2004 and comments were filed on August 20, 2004. The APSC released the report on September 30, 2004 and the Insurance and Commerce Committee heard the issue on October 20, 2004. The commissioners concluded that circumstances in the current electric generation market have not changed sufficiently since adoption of Act 204 (The Electric Utility Regulatory Reform Act of 2003) to be able to structure a large user access program that would produce economic benefits for large users while also ensuring no cost-shifting or net cost increases to remaining customers. The commissioners also concluded that there are no clear economic benefits, and more likely economic harm, that would result from moving forward with the large user access program concept at this time. The APSC closed the Feasibility of a Large User Access Program for electric service choice. The Arkansas legislature has not proposed legislation to date.

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As discussed above, legislation was enacted in Oklahoma and Arkansas that was to restructure the electric utility industry in those states. The Arkansas legislation was repealed and 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. This may result in either full recovery of generation-related regulatory assets (net of related regulatory liabilities) or a non-cash, pre-tax write-off as an extraordinary charge, depending on the transition mechanisms developed by the legislature for the recovery of all or a portion of these net regulatory assets.

The previously enacted Oklahoma and Arkansas 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. However, if utility regulators in Oklahoma and Arkansas were to adopt regulatory methodologies in the future that are not based on the cost-of-service, the continued use of SFAS No. 71 with respect to the regulatory balances related to the electric transmission and distribution assets may no longer be 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:

	2004		2003	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 130.3**	**$ 130.3**	$ 67.2	$ 67.2

Interest Rate Swaps		**7.9**		**7.9**		7.6		7.6
Price Risk Management Liabilities								
Energy Trading Contracts	**$**	**109.5**	**$**	**109.5**	$	51.4	$	51.4
Long-Term Debt and Preferred Securities								
Senior Notes	**$**	**810.9**	**$**	**864.1**	$	571.8	$	611.8
Industrial Authority Bonds		**135.4**		**135.4**		135.4		135.4
Enogex Notes		**514.1**		**556.3**		576.0		674.7
Unconsolidated Affiliate		**---**		**---**		206.2		217.8

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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.

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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, 2004 and 2003, 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, 2004. 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, 2004 and 2003, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, 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, 2004, 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 23, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 23, 2005

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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)*		Dec 31	Sep 30	Jun 30	Mar 31
Operating revenues (A)	**2004**	**$ 1,404.8**	**$ 1,324.7**	**$ 1,155.4**	**$ 1,041.7**
	2003	816.2	1,060.0	852.6	1,050.2
Operating income (A) (B) (C)	**2004**	**$ 41.7**	**$ 162.6**	**$ 82.2**	**$ 31.0**
	2003	15.3	187.3	76.6	27.7
Net income (loss) (B (C))	**2004**	**$ 9.7**	**$ 94.6**	**$ 39.0**	**$ 10.2**
	2003	(1.6)	99.5	32.2	(0.3)
Basic earnings (loss) per average common share	**2004**	**$ 0.10**	**$ 1.08**	**$ 0.44**	**$** 0.12
	2003	(0.03)	1.21	0.41	---
Diluted earnings (loss) per average common share	**2004**	**$ 0.10**	**$ 1.07**	**$ 0.44**	**$** 0.12
	2003	(0.03)	1.20	0.41	---

(A) These amounts have been restated due to Enogex s exploration and production assets, NuStar and Belvan being reported as discontinued operations during 2003.
(B) In the fourth quarter of 2003, the Company recognized a pre-tax impairment loss of approximately $9.2 million and $1.0 million in the Natural Gas Pipeline segment and Other Operations, respectively. The impairment loss in the Natural Gas Pipeline segment related to natural gas compression assets. The impairment loss in Other Operations related to the Company s aircraft.
(C) In the third quarter of 2004, the Company recognized a pre-tax impairment loss of approximately $8.6 million in the Natural Gas Pipeline segment related to four of Enogex s non-contiguous pipeline asset segments located in West Texas.

Dividends

COMMON STOCK

Common quarterly dividends paid (as declared) in 2004, 2003, and 2002 were $0.33 ¼.
Present rate $0.33 ¼
Payable 30th of January, April, July, and October

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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	P-2	A-2	F1

* The ratings of Moody s, Standard & Poor s and Fitch s reflect only the views of such organizations and each rating should be evaluated independently of the other. The ratings are not recommendations to buy, sell or hold securities. Such ratings may be subject to revision or withdrawal at any time by the credit rating agency. Moody s, Standard & Poor s and Fitch s currently maintain a stable outlook on its rating of the OG&E Senior Notes, Enogex Notes and OGE Energy Corp. commercial paper.

For further information regarding these ratings, please contact the Treasurer of the Company at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321, (405) 553-3800.

Market Prices

	2004		2003	
NEW YORK STOCK EXCHANGE	**High**	**Low**	High	Low
Common				
First Quarter	**$ 26.70**	**$ 23.03**	$ 19.37	$ 15.99
Second Quarter	**26.80**	**22.85**	22.25	17.36
Third Quarter	**26.48**	**24.10**	22.75	19.50
Fourth Quarter	**26.95**	**25.17**	24.34	21.96

Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company s management, including the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), of the effectiveness of the Company s disclosure controls and procedures, 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 recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting.

The Company has filed the Section 302 CEO and CFO certifications as exhibits to its 2004 Form 10-K. The Company has also filed the 2004 Section 303A.12(a) CEO certification to the New York Stock Exchange on June 9, 2004.

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, 2004. 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, 2004, 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	/s/ Peter B. Delaney
Steven E. Moore, Chairman of the Board, President and Chief Executive Officer	Peter B. Delaney, Executive Vice President and Chief Operating Officer
/s/ James R. Hatfield	/s/ Donald R. Rowlett
James R. Hatfield, Senior Vice President and Chief Financial Officer	Donald R. Rowlett, Vice President and Controller

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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, 2004, 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, 2004, 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, 2004, based on the COSO criteria.

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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, 2004 and 2003, 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, 2004 of OGE Energy Corp. and our report dated February 23, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 23, 2005

OG&E

P.O. Box 321

Oklahoma City, Oklahoma

73101-0321

(405) 553-3000

OGE ENERGY CORP.
Annual Meeting of Shareowners
May 19, 2005

OG&E

The undersigned hereby appoints Steven E. Moore, William E. Durrett, and Robert Kelley, and each of them severally, with full power of substitution and with full power to act with or without the other, as the proxies of the undersigned to represent and to vote all shares of stock of OGE Energy Corp. held of record by the undersigned on March 21, 2005, at the Company s Annual Meeting of Shareowners to be held on May 19, 2005, and at all adjournments thereof, on all matters coming before said meeting.

THIS PROXY, WHICH IS SOLICITED BY THE BOARD OF DIRECTORS, WILL BE VOTED AS DIRECTED. IF NO DIRECTION IS MADE, THE PROXY WILL BE VOTED FOR THE ELECTION AS DIRECTORS OF THE NOMINEES NAMED ON THE REVERSE SIDE OF THIS PROXY CARD AND FOR THE RATIFICATION OF THE APPOINTMENT OF ERNST & YOUNG LLP AS THE COMPANY S PRINCIPAL INDEPENDENT ACCOUNTANTS.

PLEASE VOTE BY INTERNET, TELEPHONE, OR MARK, DATE, SIGN AND RETURN THIS PROXY CARD PROMPTLY USING THE ENCLOSED ENVELOPE. Unless you attend and vote in person, you MUST vote by Internet, telephone, or sign and return your proxy in order to have your shares voted at the meeting.

(Continued on reverse side)

FOLD AND DETACH HERE

PLEASE DATE AND SIGN EXACTLY AS NAME APPEARS BELOW. EACH JOINT OWNER SHOULD SIGN. ATTORNEY, EXECUTOR, ADMINISTRATOR, TRUSTEE OF OTHERS SIGNING IN A REPRESENTATIVE CAPACITY SHOULD GIVE THEIR FULL TITLES.

Please mark your votes as indicated in this example X

The Board recommends a vote FOR the election as directors of the nominees named below and FOR ratification of the appointment of Ernst & Young LLP as the Company s principal independent accountants.

FOR all NOMINEES (list exceptions below)	WITHHOLD AUTHORITY to vote for all nominees

2. Ratify the appointment of Ernst & Young LLP as our principal independent accountants

FOR	AGAINST	ABSTAIN

1. Election of Directors
NOMINEES:
01 Herbert H. Champlin
02 Linda Petree Lambert
03 Ronald H. White, M.D.

Instructions: To withhold authority to vote for any individual nominee, write that nominee s name on the line above.

3. In their discretion, the proxies are authorized to vote upon such other business as may properly come before the meeting.

Choose **MLink**SM for Fast, easy and secure 24/7 online access to your future proxy materials, investment plan statements, tax documents and more. Simply log on to **Investor ServiceDirect**® at www.melloninvestor.com/isd where step-by-step instructions will prompt you through enrollment.

Discontinue mailing of duplicate Annual Report

I will attend the Annual Meeting.

X / / 2005

Signature of Shareowner Date

X / / 2005

Signature of Shareowner Date

FOLD AND DETACH HERE

OG&E
321 North Harvey Avenue
Oklahoma City, Oklahoma 73102

Admission Ticket

RETAIN FOR ADMITTANCE

Annual Meeting of

OGE Energy Corp. Shareowners

Thursday, May 19, 2005 10:00 a.m.
National Cowboy and Western Heritage Museum
1700 Northeast 63rd Street
Oklahoma City, Oklahoma

LOCATION OF THE NATIONAL COWBOY AND WESTERN HERITAGE MUSEUM

East Bound or West Bound I-44

Exit to Martin Luther King Ave., continuing north approximately .2 miles. Proceed west on Northeast 63rd Street .5 miles to National Cowboy and Western Heritage Museum.

MAP

It is important that your shares are represented at this meeting, whether or not you attend the meeting in person. To make sure your shares are represented, we urge you to vote by Internet, telephone, or complete and mail the proxy card above.

Vote by Internet or Telephone or Mail

24 Hours a Day, 7 Days a Week

Internet and telephone voting is available through 11:59 PM Eastern Time the day prior to annual meeting day.

Your Internet or telephone vote authorizes the named proxies to vote your shares in the same manner as if you marked, signed and returned your proxy card.

Internet		Telephone		Mail
http://www.proxyvoting.com/oge Use the internet to vote your proxy. Have your proxy card in hand when you access the web site.	OR	**1-866-540-5760** Use any touch-tone telephone to vote your proxy. Have your proxy card in hand when you call.	OR	Mark, sign and date your proxy card and return it in the enclosed postage-paid envelope.

If you vote your proxy by Internet or by telephone, you do NOT need to mail back your proxy card.

You can view the Annual Report and Proxy Statement on the internet at http://www.oge.com