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

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2001

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _______to _______

Commission File Number 1-12579

OGE Energy Corp.
(Exact name of registrant as specified in its charter)

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes__X__No___

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

As of February 28, 2002, 77,991,713 shares of common stock were outstanding and the aggregate market value of such shares held by non-affiliates was $1,710,358,266 based on the reported closing market price of the common stock on the New York Stock Exchange on such date of $21.93.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2002 annual meeting of stockholders is incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1. Business.

THE COMPANY

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 in the south central United States. The Company conducts these activities through two business segments, the electric utility and the energy supply 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 the jurisdiction of the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). OG&E owns and operates eight generating stations with a total capability of 5,732 megawatts. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in the State of Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area, which is the second largest market area in that state. OG&E continues to substantially impact the financial results and condition of the Company. OG&E is expected to grow moderately, consistent with historic trends. Expansion will primarily result from continued economic growth in its service territory. The citizens of Oklahoma recently passed a "right to work" referendum. This action along with other initiatives are intended to enhance the state's ability to promote itself as a business - friendly location.

The energy supply segment produces, gathers, processes, transports, markets and stores natural gas and produces, transports, and markets natural gas liquids in Oklahoma, Arkansas and west Texas. These operations are conducted primarily through Enogex Inc. and its subsidiaries ("Enogex"). Enogex is also involved in commodity sales and services related to natural gas and electric power and provides energy related services for corporate commodity price risk management and energy forward price evaluations primarily through its subsidiary, OGE Energy Resources Inc. ("OERI"). Enogex owns and operates the tenth largest natural gas pipeline system in the United States in terms of miles of pipe in service. Enogex has a significant investment in natural gas gathering, processing, transmission and storage in the major gas producing basins of Oklahoma, as well as gathering and processing operations in west Texas. Enogex also has investments in exploration and production of natural gas and oil with properties located primarily in Michigan and Oklahoma.

The Company's business strategy is to assemble a portfolio of assets, people, skills and customers that create optimal value from the convergence occurring in the electricity and natural gas markets. The Company believes its converged portfolio is well positioned to take advantage of opportunities in the south central United States.

OG&E has been and will continue to be affected by competitive changes to the utility industry. Significant changes already have occurred in the wholesale electric markets at the federal level and significant changes are expected at the retail level in the states served by OG&E. In Oklahoma, legislation was passed in April 1997 to provide for the orderly restructuring of the electric industry with the goal to provide retail customers with the ability to choose their electric suppliers by July 1, 2002. In May 2001, the Oklahoma Legislature passed legislation postponing the scheduled start date for customer choice from July 1, 2002 until at least 2003. In addition to postponing the date for customer choice, the

legislation calls for a nine-member task force to further study the issues surrounding deregulation. In April 1999, Arkansas passed a law calling for restructuring of the electric utility industry at the retail level. The law initially targeted customer choice of electricity providers by January 1, 2002, but the law was amended to delay customer choice until October 1, 2003. See "Electric Operations - Regulation and Rates - State Restructuring Initiatives" for further discussion of these developments.

In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of OG&E. OG&E's rates had last been formally reviewed in 1995. In the filing, the OCC requested that OG&E submit information in accordance with OCC minimum standard filing requirements by January 28, 2002, for a test year ending September 30, 2001. On January 28, 2002, OG&E filed its response requesting a $22 million annual rate increase. OG&E's filing also outlined several new customer programs and offered not to seek another increase for at least three years. It has been 16 years since OG&E requested a rate increase. A final order in the OG&E rate case is not expected until later in 2002. At this time, management cannot predict the outcome of this rate case or the impact on its consolidated financial position or results of operation. See "Electric Operations - Regulation and Rates - Recent Regulatory Matters" for further discussion of these developments.

The Company was incorporated in August 1995 in the State of Oklahoma and its executive offices are located at 321 North Harvey, P. O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone (405) 553-3000.

ELECTRIC OPERATIONS

General

As stated previously, the electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E. OG&E furnishes retail electric service in 270 communities and their contiguous rural and suburban areas. During 2001, seven other communities and two rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from

OG&E for resale. The service area, with an estimated population of 1.7 million, covers approximately 30,000 square miles in Oklahoma and western Arkansas; including Oklahoma City, the largest city in Oklahoma, and Ft. Smith, Arkansas, the second largest market in that state. Of the 279 communities served, 252 are located in Oklahoma and 27 in Arkansas. Approximately 90 percent of total electric operating revenues for the year ended December 31, 2001, were derived from sales in Oklahoma and the remainder from sales in Arkansas.

OG&E's system control area peak demand as reported by the system dispatcher for the year was approximately 5,788 megawatts on July 12, 2001. OG&E's load responsibility peak demand was approximately 5,600 megawatts on July 12, 2001, resulting in a capacity margin of approximately 14.7 percent. As reflected in the table on page 3 and in the operating statistics on page 4, total kilowatt-hour sales decreased 1.3 percent in 2001 as compared to an increase of 5.9 percent in 2000 and a decrease of 2.2 percent in 1999. Kilowatt-hour sales to OG&E's customers ("system sales") decreased 1.9 percent in 2001, due to milder weather. Cooling degree days and heating degree days were approximately 5.1 percent and 5.3 percent below 2000 levels, respectively. Sales to other utilities and power marketers ("off-system sales") increased 65.2 percent in 2001 and decreased 31.5 percent and 48.6 percent in 2000 and 1999, respectively.

Variations in kilowatt-hour sales for the three years are reflected in the following table:

SALES (Millions of Kwh)

	2001	**Increase/ (Decrease)**	2000	Increase/ (Decrease)	1999	Increase/ (Decrease)
System Sales	**24,518**	**(1.9%)**	25,002	6.5%	23,468	(0.7%)
Off-System Sales	**423**	**65.2%**	256	(31.5%)	374	(48.6%)
Total Sales	**24,941**	**(1.3%)**	25,258	5.9%	23,842	(2.2%)

OG&E is subject to competition in various degrees from government-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators. See Item 3 "Legal Proceedings" for a further discussion of this matter. Oklahoma law forbids the granting of an exclusive franchise to a utility for providing electricity.

Besides competition from other suppliers or marketers of electricity, OG&E competes with suppliers of other forms of energy. The degree of competition between suppliers may vary depending on relative costs and supplies of other forms of energy. See "Electric Operations - Regulation and Rates - Recent Regulatory Matters" for a discussion of the potential impact on competition from federal and state legislation.

OKLAHOMA GAS AND ELECTRIC COMPANY
CERTAIN OPERATING STATISTICS

	Year Ended December 31		
	2001	2000	1999
ELECTRIC ENERGY:			
(Millions of Kwh)			
Generation (exclusive of station use)	**23,041**	23,327	21,788
Purchased	**3,703**	3,634	3,795
Total generated and purchased	**26,744**	26,961	25,583
Company use, free service and losses	**(1,803)**	(1,703)	(1,741)
Electric energy sold	**24,941**	25,258	23,842
ELECTRIC ENERGY SOLD:			
(Millions of Kwh)			
Residential	**7,982**	7,974	7,509
Commercial and industrial	**12,401**	12,729	11,985
Public street and highway lighting	**71**	70	69
Other sales to public authorities	**2,530**	2,458	2,354
System sales for resale	**1,534**	1,771	1,551
Total system sales	**24,518**	25,002	23,468
Off-system sales	**423**	256	374
Total sales	**24,941**	25,258	23,842
ELECTRIC OPERATING REVENUES:			
(Dollars in Thousands)			
Electric Revenues:			
Residential	**$ 578,881**	$ 575,656	$ 515,299
Commercial and industrial	**637,962**	643,576	557,884
Public street and highway lighting	**10,877**	10,301	9,736
Other sales to public authorities	**127,954**	124,217	108,159
System sales for resale	**52,506**	58,117	42,918
Provision for FERC rate refund	**(1,000)**	---	---
Total system sales	**1,407,180**	1,411,867	1,233,996
Off-system sales	**12,977**	12,948	27,894
Total Electric Revenues	**1,420,157**	1,424,815	1,261,890
Miscellaneous revenues	**36,645**	28,770	24,954
Total Electric Operating Revenues	**$ 1,456,802**	$ 1,453,585	$ 1,286,844

NUMBER OF ELECTRIC CUSTOMERS:
(At end of period)

Residential	**609,408**	603,826	599,702
Commercial and industrial	**87,511**	86,659	86,837
Public street and highway lighting	**250**	250	249
Other sales to public authorities	**12,566**	11,615	11,151
Sales for resale	**62**	52	56
Total	**709,797**	702,402	697,995
RESIDENTIAL ELECTRIC SERVICE:			
Average annual use (Kwh)	**13,131**	13,264	12,546
Average annual revenue	**$ 952.32**	$ 957.54	$ 860.98
Average price per Kwh (cents)	**$ 7.25**	$ 7.22	$ 6.86

Regulation and Rates

OG&E's retail electric tariffs in Oklahoma are regulated by the OCC, and in Arkansas by the APSC. 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.

As part of the corporate reorganization whereby the Company became the holding company parent of OG&E, OG&E obtained the approval of the OCC. The order of the OCC authorizing OG&E to reorganize into a holding company structure contains certain provisions which, among other things, ensure the OCC access to the books and records of the Company and its subsidiaries relating to transactions with OG&E; require the Company and its subsidiaries to employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers; and prohibit the Company from pledging OG&E assets or income for affiliate transactions.

For the year ended December 31, 2001, approximately 87 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC, and five percent to the FERC.

Recent Regulatory Matters

The OCC Staff ("Staff") annually conducts a review ("Matrix Review") to assess utility operations. The purpose of the Matrix Review is to enable the Staff to specifically identify regulated utilities that have experienced material or significant changes in operating characteristics, or in the underlying cost of service, as a means of evaluating the need to pursue rate hearings. The Staff also uses the Matrix Review to identify regulated utilities that require a Staff review of some specific operational activity conducted by the utility. The Matrix Review is composed of 11 indicators that are the basic guide for the Staff's initial review of a regulated utility. The 11 indicators include such items as the time from a utility's last rate review and service quality complaints. Each indicator is given a rating by the Staff from zero to three. A rating of zero is considered not relevant, a rating of one is considered slightly relevant, a rating of two is considered moderately relevant, while a rating of three is considered significantly relevant. The Staff believes that an aggregate rating of less than ten and with no individual indicator receiving a rating of three, should indicate that no further assessment is required. Any rating above these levels could result in a Staff recommendation requesting that a further review should be performed. In July 2001, the OCC held a hearing at which the Staff reported the results of its Matrix Review of OG&E. The review resulted in an aggregate score of 17 for OG&E, with only one indicator "Time since last formal rate review", achieving a rating of three. OG&E's last formal rate review by the Staff occurred in 1995. As part of its written report, the Staff recommended that a general rate review be performed on OG&E.

In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of OG&E. In the filing, the Staff requested that OG&E submit information in accordance with OCC minimum standard filing requirements by January 28, 2002, for a test year ending September 30, 2001. On December 14, 2001, OG&E, citing the need for investment in security and system reliability, filed a notice with the OCC of its intent to seek an increase in OG&E's electric rates. On January 28, 2002, OG&E filed testimony with the OCC supporting OG&E's request for a $22 million annual rate increase. If granted, the increase would be the first for OG&E since 1985. Over the past 16 years, OG&E has had rate reductions of more than $142 million. Attempting to make security investments at the proper level, OG&E developed a set of guidelines to arrive at the appropriate steps to minimize the ability to cause 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. Approximately $10 million of the rate increase requested by OG&E was to invest in increased security. The additional $12 million is for investment in increased system reliability and for increased utility costs. OG&E has added new generation capacity to meet growing customer demand and has determined a need to increase expenditures for distribution system reliability that has been brought about, in no small part, by a series of record-breaking storms, including a 1995 windstorm in the Oklahoma City area affecting 175,000 customers, 1999 tornadoes affecting about 150,000 customers and knocking out a power plant, July 2000 thunderstorms affecting 110,000 customers, a Christmas 2000 ice storm affecting 140,000 customers, Memorial Day 2001 storms leaving 143,000 customers without power and at least two other storms affecting at least 100,000 customers each. Additionally, OG&E has experienced an overall increase in operating expenses. As part of it's filing, OG&E also is seeking approval to offer several new rate program choices to customers. One such pilot program involves flat billing. This option would set a customer's bill at a fixed dollar amount and would not change throughout the year regardless of the amount of power consumed. The bill amount would then be adjusted in the following year based on the previous year's usage and other factors. Another proposed rate program, a Green Power option, would involve OG&E contracting with wind generators to purchase a quantity of wind-generated energy, then offering that power to customers. The rate would reflect the higher cost of wind-generated power. Also included in the filing was OG&E's offer to not seek a rate increase for three years. A final order in the OG&E rate case is not expected until later in 2002.

In January 2002, a significant ice storm hit OG&E's service territory. This ice storm inflicted major damage to the transmission and distribution infrastructure. Total expenditures are currently estimated at $136 million. Based on current estimates, the vast majority of these expenditures for restoration of the utility's system will be capitalized as part of the utility's plant. The Company believes that the capital costs will be considered in the pending rate case. The remaining costs will be deferred pending regulatory approval of a recovery plan.

As previously reported, certain aspects of OG&E's electric rates recently have been addressed by the OCC. In March 2000, the OCC approved, and OG&E implemented, the Acquisition Premium Credit Rider ("APC Rider") reflecting the completion of the recovery of the amortization premium paid by OG&E when it acquired Enogex in 1986. The effect of the APC Rider is to remove $10.7 million annually from the amount being recovered by OG&E from its Oklahoma customers in current rates.

In June 2000, the OCC approved modifications to OG&E's Generation Efficiency Performance Rider ("GEP Rider"). The GEP Rider was established initially in 1997 in connection with OG&E's last general rate review and was intended to encourage OG&E to lower its fuel costs by: (i) allowing OG&E to collect one-third of the amount by which its fuel costs were below a specified percentage (96.261%) of the average fuel costs of certain other investor-owned utilities in the region; and (ii) disallowing the collection of one-third of the amount by which its fuel costs exceeded a specified percentage (103.739%) of the average fuel costs of other investor-owned utilities. The modifications enacted in June 2000 had the effect of reducing the amount OG&E could recover under the GEP Rider by: (i) changing OG&E's peer group to include utilities with a higher coal-to-gas generation mix; (ii) reducing the amount of fuel costs that can be recovered if OG&E's costs exceed the new peer group by changing the percentage above which OG&E will not be allowed to recover one-third of the fuel costs from Oklahoma customers from 103.739 percent to 101.0 percent; (iii) reducing OG&E's share of cost savings as compared to its new peer group from 33 percent to 30 percent; and (iv) limiting to $10.0 million the amount of any awards paid to OG&E or penalties charged to OG&E. For the period between July 1, 2001 and June 30, 2002, OG&E estimates that it will recover $5.1 million under the GEP Rider. The GEP Rider is scheduled to

expire in June 2002, however, the OCC could decide to establish a similar reward mechanism in a subsequent action upon proper showing.

The final action addresses the competitive bid process of OG&E's gas transportation needs following which OG&E's affiliate, Enogex, contracted to provide gas transportation service to all of OG&E's generation plants. In the 1997 Order, the OCC approved a stipulation wherein OG&E agreed to initiate a competitive bidding process for gas transportation service to its gas-fired plants, with the competitive services commencing no later than April 30, 2000. The order also set annual compensation for the transportation services provided by Enogex to OG&E at $41.3 million annually until March 1, 2000, at which time the rate would drop to $28.5 million (reflecting removal of the APC Rider, upon the completion of the recovery from customers of the amortization premium paid by OG&E when it acquired Enogex in 1986) and remain at that level until competitively-bid gas transportation began. Final firm bids were submitted by Enogex and other pipelines on April 15, 1999. In July 1999, OG&E filed an application with the OCC requesting approval of a performance-based rate plan for its Oklahoma retail customers from April 2000 until the introduction of customer choice for electric power in July 2002. As part of this application, OG&E stated that Enogex had submitted the only viable bid ($33.4 million per year) for gas transportation to OG&E's six gas-fired power plants that were the subject of the competitive bid. As part of its application to the OCC, OG&E offered to discount Enogex's bid from $33.4 million annually to $25.2 million annually. OG&E executed a gas transportation contract with Enogex under which Enogex continues to serve the needs of OG&E's power plants at a price to be paid by OG&E of $33.4 million annually and, if OG&E's proposal had been approved by the OCC, OG&E would have recovered a portion of such amount ($25.2 million) from its customers. OG&E negotiated with the Staff, the Office of the Oklahoma Attorney General and a coalition of industrial customers in an effort to settle all issues (including the competitive bid process) associated with its application for a performance-based rate plan. When these negotiations failed, OG&E withdrew its application, which withdrawal was approved by the OCC in December 1999.

In July 2000, OG&E entered into a stipulation (the "Stipulation") with the Staff, the Office of the Attorney General and a coalition of industrial customers regarding the competitive bid process of OG&E's gas transportation service. In June 2001, the OCC approved the Stipulation declaring the Stipulation to be fair, just and reasonable and representing a reasonable settlement of the issues and thereby serving the public interest. OG&E had previously collected $28.5 million on an annual basis through its base rate and APC Rider for gas transportation services from Enogex for the power plant requirements covered by the competitive bid. The Stipulation permits OG&E to recover $25.2 million annually for the gas transportation services provided by Enogex pursuant to the competitive bid process. The Stipulation directs OG&E to reduce rates to its Oklahoma retail customers by approximately $2.7 million per year through the implementation of a Gas Transportation Adjustment Credit Rider ("GTAC Rider"). The GTAC Rider is a credit for gas transportation cost recovery and is applicable to and becomes part of each Oklahoma retail rate schedule to which OG&E's Fuel Cost Adjustment rider applies. The GTAC Rider became effective with the first billing cycle of July 2001, and will remain in effect until amended by OG&E at the direction of the OCC.

On February 13, 1998, the APSC staff filed a motion for a show cause order to review OG&E's electric rates in the State of Arkansas. The Staff recommended a $3.1 million annual rate reduction (based on a test year ended December 31, 1996). The Staff and OG&E reached a settlement for a $2.3 million annual rate reduction, which was approved by the APSC in August 1999.

State Restructuring Initiatives

Oklahoma: As previously reported, Oklahoma enacted in April 1997 the Electric Restructuring Act of 1997 (the "Act"), which was designed to provide for choice by retail customers of their electric supplier by July 1, 2002. Additional implementing legislation was to be adopted by the Oklahoma Legislature to address many specific issues associated with the Act and with deregulation. In May 2000, a bill addressing the specific issues of deregulation was passed in the Oklahoma State Senate and then was defeated in the Oklahoma House of Representatives. In May 2001, the Oklahoma Legislature passed Senate Bill 440 ("SB 440"), which postponed the scheduled start date for customer choice from July 1, 2002 until at least 2003. In addition to postponing the date for customer choice, the SB 440 calls for a nine-member task force to further study the issues surrounding deregulation. The task force includes the Governor or his designee, the Attorney General, the OCC Chair and several legislative leaders, among others. The Company will continue to participate actively in the legislative process and expects to remain a competitive supplier of electricity. The Company cannot predict what, if any, legislation will be adopted at the next legislative session.

Arkansas: 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, like the Oklahoma law, would significantly affect OG&E's future operations. OG&E's electric service area includes parts of western Arkansas, including Fort Smith, the second-largest metropolitan market in the state. The Restructuring Law initially targeted customer choice of electricity providers by January 1, 2002. In February 2001, the Restructuring Law was amended to delay the start date of customer choice of electric providers in Arkansas until October 1, 2003, with the APSC having discretion to further delay implementation to October 1, 2005. The Restructuring Law also provides that utilities owning or controlling transmission assets must transfer control of such transmission assets to an independent system operator, independent transmission company or regional transmission group, if any such organization has been approved by the FERC. Other provisions of the Restructuring Law permit municipal electric systems to opt in or out, permit recovery of stranded costs and transition costs and require filing of unbundled rates for generation, transmission, distribution and customer service. OG&E filed preliminary business separation plans with the APSC on August 8, 2000. The APSC has established a timetable to establish rules implementing the Arkansas restructuring statutes.

Automatic Fuel Adjustment Clauses

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to that component in cost-of-service for ratemaking, are charged to substantially all of OG&E's electric customers through automatic fuel adjustment clauses, which are subject to periodic review by the OCC, the APSC and the FERC. As discussed previously, in June 2001, the OCC approved the GTAC Rider for $2.7 million annually. The GTAC Rider is a credit for gas transportation cost recovery. In March 2000, the OCC approved the APC Rider for $10.7 million annually. The purpose of the APC Rider is to credit the Oklahoma retail customers for the completion of the OCC authorized recovery of the premium paid by OG&E when it acquired Enogex in 1986. The GTAC Rider and the APC Rider are both applicable to each Oklahoma retail rate schedule to which OG&E's fuel cost adjustment clause applies.

National Energy Legislation

Federal law imposes numerous responsibilities and requirements on OG&E. The Public Utility Regulatory Policies Act of 1978 requires electric utilities, such as OG&E, to purchase electric power

from, and sell electric power to, qualified cogeneration facilities and small power production facilities ("QFs"). 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 to QFs on a non-discriminatory basis at a rate that is just and 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.

The efforts to increase competition in the electric industry at the retail level in Oklahoma and Arkansas have been paralleled and even surpassed by efforts 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 ("IPPs"). 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 trade. Moreover, power marketers are an increasingly important presence in the industry. 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, almost all of it from IPPs.

Notwithstanding these developments in the wholesale power market, 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, FERC only encouraged utilities to join and place their transmission systems under the operational control of independent system operators ("ISOs"). On December 20, 1999, FERC issued Order 2000, its final rule on regional transmission organizations ("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, 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.

OG&E is a member of the Southwest Power Pool ("SPP"), the regional reliability organization for Oklahoma, Arkansas, Kansas, Louisiana, Missouri and part of Texas. OG&E participated with the SPP in the development of regional transmission tariffs and executed an Agency Agreement with the SPP to facilitate interstate transmission operations within this region. In October 2000, the SPP filed its application with the FERC to become an RTO. In July 2001, the FERC determined that the SPP did not have adequate scope and configuration to be granted RTO status. The SPP was encouraged to explore the possibility of joining an RTO to be formed in the southeastern region of the United States and to explore the feasibility of becoming a part of the recently approved RTO being established by the

Midwest Independent System Operator ("MISO"). The SPP and MISO entered negotiations during the late summer of 2001 to combine the SPP and MISO and to form a new regional transmission entity that would combine the control areas of MISO and SPP, capture certain synergies that would be available from the combined organization, and allow member companies in the SPP certain options with respect to membership in the combined organization. The officers of MISO and of SPP, under the direction of their respective Boards of Directors have developed documentation to effect the merger of SPP and MISO into a new organization, and the transaction has been approved by the SPP Board of Directors and the required number of SPP member companies. OG&E intends to meet its obligations under Order 2000 and under the Restructuring Law in Arkansas first by executing a Conditional Withdrawal Agreement with the SPP. The Conditional Withdrawal Agreement will have the effect of terminating OG&E's membership in the SPP, except for regional reliability purposes, at such time as the MISO - SPP combination has received all necessary regulatory approvals and the transaction is closed. Following the closing of the transaction, OG&E currently anticipates that it will join the MISO. The transfer of operational control of OG&E's transmission system to a FERC-approved RTO is not expected to significantly impact OG&E's financial results. Yet, it is expected to increase the markets in which OG&E can sell power at wholesale and, at the same time, to increase competition in such wholesale markets. As a low-cost producer of electricity with two of the most efficient power plants in the country, OG&E expects to remain a competitive supplier of electricity.

Another impact of complying with FERC's Order 888 is a requirement for utilities to offer a transmission tariff that includes network transmission service ("NTS") to transmission customers. NTS allows transmission service customers to fully integrate load and resources on an instantaneous basis, in a manner similar to how OG&E has historically integrated its load and resources. Under NTS, OG&E and participating customers share the total annual transmission cost for their combined joint-use systems, net of related transmission revenues, based upon each company's share of the total system load. Management expects minimal annual expenses as a result of Orders 888 and 889.

Regulatory Assets and Liabilities

As discussed previously, legislation was enacted in Oklahoma and Arkansas that was to restructure the electric utility industry in those states. Although implementation of this restructuring legislation has been delayed, if and when implemented this legislation would deregulate OG&E's electric generation assets and discontinue the use of Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation" with respect to the related regulatory assets. 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 of up to $28 million, depending on the transition mechanisms developed by the legislature for the recovery of all or a portion of these net regulatory assets.

The 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 assets is appropriate. However, if utility regulators in Oklahoma and Arkansas were to adopt regulatory methodologies in the future that are not based on cost-of-service, the continued use of SFAS No. 71 with respect to the regulatory assets 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 Arkansas, and other factors are expected to significantly 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.

Rate Activities and Proposals

As previously discussed, the OCC initiated a rate review proceeding for OG&E in September of 2001. The review is performed to capture the effects of changing costs, customer growth changes, changes in technology, or changes in customer's needs. The review provides an opportunity by the OCC and OG&E to review rate structures, to review terms and conditions of service, to address any new customer issues, and to make modifications as needed in meeting the needs of OG&E's customers, employees and the Company's shareholders.

OG&E has proposed in this rate proceeding several new programs and rate options, as well as modifications to existing rate structures. Some of the new programs being promoted include a Guaranteed Flat Bill ("GFB") option for Residential and small General Service accounts. These voluntary GFB programs will allow qualifying customers the opportunity to purchase their electricity needs at a set price for an entire year. A second option provided to customers in this proceeding is a "Green Power" option. This option is a wind power program and will be available as a voluntary option to all of OG&E's Oklahoma customers that wish to purchase Green Power. A third new rate offering is levelized demand. This program will be beneficial for medium to large size customers of consistent demand levels who wish to reduce monthly billing variability. Setting a flat demand price for the entire year eliminates seasonal demand price variability. The levelized demand offering is not for every customer, but many customers will benefit from this tariff. Finally, the last new program being offered to OG&E's commercial and industrial customers is voluntary load curtailment. This program will provide customers with the opportunity to curtail on a voluntary basis when OG&E system conditions merit curtailment action. They will receive payment for their curtailment response. This voluntary curtailment program seeks customers that can curtail on most curtailment event days, but may not be able to curtail every time that a curtailment event is required.

OG&E believes that due to the positive economic impact on Oklahoma when new power plants are built, it is in Oklahoma's best interest to encourage the development of new power plants. A significant number of new power plants have been proposed in Oklahoma and a number of them are actually under construction.

OG&E has proposed the Transmission Investment Recovery Rider ("TIR Rider") which would be applicable to investments necessary for increased transmission sevice and interconnect costs not funded by a new transmission customer (such as an IPP) or for investment to improve available transfer capability as defined and approved by the RTO. While the transmission system in Oklahoma is serving native load customers well, it is evident that transmission upgrades will be necessary to accommodate the growing number of power generators. OG&E believes that increased investments in the transmission infrastructure along with the investments already occurring in Oklahoma and surrounding states to construct new generating plants, will produce a viable regional wholesale power marketplace. The enhanced transmission system will allow electric utilities in Oklahoma more options for competitively priced power to evaluate with respect to load growth of customers they have an obligation to serve. To

the extent that wholesale competition is enhanced, the ultimate cost of electricity to Oklahoma customers is expected to be less than would be the case in the absence of competition. To the extent that OG&E would be required to pay for certain types of transmission upgrades to the system, OG&E believes the TIR Rider would provide a timely and reasonable means of recovering costs.

The TIR Rider would be a per kilowatt-hour rate, applied monthly to all Oklahoma retail customers bills to collect revenue requirements associated with prospective types of transmission investments. The TIR Rider rate would be determined on a calendar year basis, recognizing revenue requirements for investment during the year and the effects of depreciation on investment incurred in prior years. At the time of OG&E's next rate review, the remaining value of the transmission assets applicable to the TIR Rider will be placed into rate base and the components of the TIR Rider redetermined.

OG&E also is proposing a Coal Utilization Performance Rider ("CUP Rider"), the CUP Rider is designed to reward OG&E based on its performance in the utilization of its coal generation facilities. The greater the coal plant utilization, the greater the benefits received by OG&E's customers. OG&E's coal plants are among the nations most efficient and the energy produced by those plants displaces higher cost energy. The CUP Rider provides additional incentive for OG&E by encouraging OG&E to aggressively pursue even greater efficiencies from these best-in-class plants. Additional CUP Rider incentives begin at 72 percent coal utilization and increase as percentages rise above the 72 percent threshold level. For 2001, coal plant utilization was 73 percent. It is no small task to increase this utilization percentage, but the customers, the stockholders, and OG&E all benefit if OG&E is able to increase coal plant utilization.

These new rate options coupled with OG&E's existing rate choices should be very valuable for OG&E's customers in making the best rate choices for their particular electricity needs.

Fuel Supply

During 2001, approximately 73 percent of the OG&E-generated energy was produced by coal-fired units and 27 percent by natural gas-fired units. A slight decline in the percentage of coal generation in future years is expected to result from increases in natural gas-fired generation required to meet growing energy needs while coal generation will remain fairly constant. Over the last five years, the average cost of fuel used, by type, per million British thermal unit ("MMBtu") was as follows:

	2001	2000	1999	1998	1997
Coal..............	**$0.81**	$0.87	$0.85	$0.85	$0.84
Natural Gas.......	**$4.91**	$4.93	$3.14	$2.83	$3.60
Weighted Avg......	**$1.97**	$1.96	$1.54	$1.48	$1.39

A portion of the fuel cost is included in base rates and differs for each jurisdiction. The portion of these costs that is not included in base rates is recovered through automatic fuel adjustment clauses. See "Electric Operations - Regulation and Rates - Automatic Fuel Adjustment Clauses."

Coal-Fired Units: All of OG&E's coal units, with an aggregate capability of 2,539 megawatts, are designed to burn low sulfur western coal. OG&E purchases coal primarily under long-term contracts. During 2001, OG&E purchased 8.7 million tons of coal from the following Wyoming suppliers: Kennecott Energy Company, Thunder Basin Coal Company, Powder River Coal Company, and Triton Coal Company. The combination of all coal has a weighted average sulfur content of less than 0.3 percent and can be burned in these units under existing federal, state and local environmental standards

(maximum of 1.2 pounds of sulfur dioxide per MMBtu) without the addition of sulfur dioxide removal systems. Based upon the average sulfur content, OG&E units have an approximate emission rate of 0.63 pounds of sulfur dioxide per MMBtu. In anticipation of the more strict provisions of Phase II of The Clean Air Act, which began in the year 2000, OG&E had contracts in place to allow for a supply of very low sulfur coal from suppliers in the Powder River Basin to meet the new sulfur dioxide standards.

OG&E has continued its efforts to maximize the utilization of its coal units at both the Sooner and Muskogee generating plants. See "Environmental Matters" for a discussion of an environmental proposal that, if implemented as proposed, could inhibit OG&E's ability to use coal as its primary boiler fuel.

Gas-Fired Units: OG&E utilizes a Request for Bid to acquire natural gas supplies. For calendar year 2002, successful bids wer accepted that are expected to supply approximately 70 percent of OG&E's estimated annual gas requirements. The additional gas requirements will be secured through monthly and day-to-day purchases as needed.

In 1993, OG&E began utilizing a natural gas storage facility that allows OG&E to optimize the use of its generation assets.

ENOGEX

The energy supply segment includes Enogex, which owns and operates the tenth largest natural gas pipeline system in the United States in terms of miles of pipe in service. Enogex is an Oklahoma intrastate natural gas pipeline, which also conducts operations in related business through subsidiary companies. These businesses include gas processing operations and natural gas liquids marketing ("Gas Processing"); exploration and production of oil and natural gas ("Exploration and Production"); commodity sales and services related to natural gas and electric power ("Marketing"); and the gas gathering and interstate gas transmission operations ("Gas Transportation").

Enogex has a significant investment in natural gas gathering, processing, transmission and storage in the major gas producing basins of Oklahoma, as well as gathering and processing operations in west Texas. Enogex also has a seventy-five percent interest in the NOARK Pipeline System Limited Partnership ("NOARK"), which owns the Ozark Gas Transmission System ("Ozark"). Ozark is a FERC regulated interstate pipeline that is operated by Enogex, and is located from southeast Oklahoma through Arkansas and terminates just across the state line in southeast Missouri. Enogex, through its affiliate OERI, markets energy products, including natural gas and electric power, and provides energy related services for corporate commodity price risk management and energy forward price evaluations. Enogex also has investments in exploration and production of natural gas and oil with properties located primarily in Michigan and Oklahoma.

Recent Actions: In 2001, Enogex filed for fuel-recovery rate adjustments with FERC to resolve the under-recovery of pipeline system fuel expenses. FERC approved the new rates and they became effective on March 1, 2001.

Gas Transportation: One of Enogex's primary lines of business is the transportation of natural gas, which includes both interstate and intrastate transportation along with natural gas gathering in Oklahoma, Arkansas and Texas. Interruptible transportation service is offered to most interstate and intrastate pipelines and end-users connected to Enogex's systems. As mentioned previously, Enogex owns and operates the tenth largest natural gas pipeline in the United States in terms of miles of pipe in

service (approximately 9,700 miles) that gather and transport gas from the Arkoma basin of eastern Oklahoma and Arkansas, the Anadarko basin of western Oklahoma and the Permian basin of west Texas.

In July 1999, Enogex acquired Tejas Transok Holding, L.L.C. and its subsidiaries ("Transok"). Transok was established in 1955 to transport boiler fuel to the gas-powered electric generating facilities of Public Service Company of Oklahoma ("PSO"). PSO, a subsidiary of Central and South West Corporation, is the second largest electric utility in Oklahoma, serving the Tulsa market. Transok was acquired by PSO in 1961 and maintained a sole-supplier relationship with PSO until 1998, when Oklahoma Natural Gas began supplying gas to three of the PSO generating stations pursuant to a competitive bid process put in place by the OCC. Notwithstanding the loss of the sole-supplier status, PSO remains an important customer of Transok. Transok continues to provide gas transmission delivery services to all of PSO's gas-fueled electric generation units in Oklahoma under a firm intrastate transportation contract. The current contract, which expires January 1, 2003, provides for a monthly demand charge plus a variable transportation rate depending on the origins of the gas supply being transported. In addition, Transok provides straight fee transportation services to West Texas Utilities ("WTU"), an affiliate of PSO, for gas delivery service to certain WTU generating stations in the Texas Panhandle under a contract that expires on December 31, 2004. In 2001, Transok's revenues from the PSO and WTU contracts were $13.3 million and $2.5 million, respectively.

The rates charged by Enogex and Transok for transporting natural gas on behalf of an interstate natural gas pipeline company or a local distribution company served by an interstate natural gas pipeline company are subject to the jurisdiction of the FERC under Section 311 of the Natural Gas Policy Act. This statute entitles Enogex and Transok to charge a "fair and equitable" rate that is subject to review and approval by the

FERC at least once every three years. This rate review may involve an administrative-type trial and an administrative appellate review. In addition, Enogex and Transok have agreed to open their systems to all interstate shippers that are interested in transporting natural gas through the systems. Enogex and Transok are required to conduct this transportation on a non-discriminatory basis, although this transportation is subordinate to that performed for OG&E and PSO. This decision does not increase appreciably the federal regulatory burden on Enogex and Transok, but does give Enogex and Transok the opportunity to utilize any unused capacity on an interruptible basis and thus increase its transportation revenues.

Gas Processing: With the acquisition of Transok, Enogex is now one of the largest gas processors in the state of Oklahoma. Enogex now owns 11 gas processing plants, with an inlet capacity of over one billion cubic feet per day ("Bcfd"), and has ownership interest in two other gas processing plants, with an inlet capacity of 310 million cubic feet per day ("MMcfd"), on a net percentage of ownership basis. The gas processing operations are conducted through Enogex Products Corporation ("Products") and Transok. Products has been active since 1968 in the processing of natural gas and marketing of natural gas liquids. The NuStar Joint Venture ("NuStar"), in which Products owns an 80 percent interest, has been engaged in the processing of natural gas since 1951. Products' and NuStar's natural gas processing plant operations consist of the extraction and sale of natural gas liquids. The products extracted from Transok's natural gas stream include marketable ethane, propane, butanes and natural gasoline mix. The residue gas remaining after the liquid products have been extracted consists primarily of ethane and methane. All Transok processing plants are cryogenic expander processing plants capable of recovering or rejecting ethane.

A portion of the commercial grade propane processed at Products Calumet facility and two Transok plants are sold on the local market. The other natural gas liquids produced by Products and Transok are delivered into pipeline facilities of Koch Hydrocarbon ("Koch") and transported to Conway, Kansas and Mont Belvieu, Texas, where they are sold under contract or on the spot market. Ethane,

which is produced at all plants except Calumet, is sold under a contract with Equistar Chemicals LP, Dow Hydrocarbons and Resources Inc. and Koch. Natural gas liquids from NuStar are sold to the Huntsman Chemicals plant (formerly Rexene Chemicals) in Midland, Texas.

In processing and marketing natural gas liquids, Enogex competes against virtually all other gas processors producing and selling natural gas liquids. Enogex believes it will be able to continue to compete favorably against such companies. With respect to the factors affecting the natural gas liquids industry generally, as the price of natural gas liquids fall without a corresponding decrease in the price of natural gas, it may become uneconomical to extract certain natural gas liquids. As explained under Item 7 of this report, this factor had a significant adverse impact on the results of Enogex during 2001. As to factors affecting Enogex specifically, the volume of natural gas processed at their plants is dependent upon the volume of natural gas gathered by Enogex and other gatherers through their pipeline systems. Generally, if the volume of natural gas gathered increases, then the volume of liquids extracted by Enogex should also increase.

Marketing: Commodity sales and services related to natural gas and electric power are conducted by Enogex primarily through its subsidiary OERI.

Natural Gas - Enogex's gas marketing is conducted through OERI. OERI also markets natural gas developed by Enogex Exploration Corporation ("Exploration") when volumes are sufficiently concentrated to justify OERI's involvement. OERI did not perform the gas purchasing function for OG&E during 2001.

OERI focuses on serving customers along the natural gas value chain, from producers to end-users, by purchasing natural gas both on and off the Enogex pipeline system and reselling to pipelines, local distribution companies and end-users, including the electric generation sector.

The geographic scope of marketing efforts has been focused largely in the mid-continent area of the United States. These markets allow OERI to leverage the strategic location of the Enogex system and its multiple interconnections with the interstate pipeline system that moves natural gas from the major producing basins in the south central United States to the natural gas consuming north central and mid Atlantic regions of the United States.

OERI participates in both long-term markets and short-term "spot" markets for natural gas. Although OERI continues to increase its focus on long-term sales, short-term sales of natural gas will continue to play a critical role in overall strategy because they provide an important source of market intelligence as well as an important portfolio balancing function.

OERI's risk management skills afford its customers the opportunity to tailor the risk profile and composition of their natural gas portfolio. At the same time, price risk beyond OERI's risk tolerance on extended term gas purchase or sales contracts is hedged on the New York Mercantile Exchange futures exchange in accordance with corporate policy.

Electricity - OERI participates actively as a wholesale purchaser and reseller in the physical wholesale power markets of the mid-continent region. It has a fully-staffed 24-hour power desk that continually monitors the physical marketplace seeking to create value by matching market participants with power surpluses to those market participants with power needs. The expertise of OERI's power desk in managing customer relationships and the complexities of the transmission grid enable the continued ability to extract value from the marketplace. As the physical power broker for OG&E, OERI assists in the sale to and purchase from the physical power markets as required to meet the needs of

OG&E. Since March 2000, virtually all of OG&E's surplus power sales activity has been performed by OERI.

Exploration and Production: The exploration and production activities are conducted through Exploration, which was formed in 1988 primarily to engage in the development and production of oil and natural gas. Exploration focused its early drilling activity in the Antrim Devonian shale trend in the state of Michigan but in recent years has concentrated on drilling opportunities in Oklahoma. As part of this refocusing, Exploration sold its interests in Texas and Utah during 2000. As of December 31, 2001, Exploration had interests in over 378 active wells and estimated proved reserves of 50,387 million cubic fees equivalent. In 1998, OERI initiated a program of hedging the future gas selling price on a portion of Exploration's net production through commodity futures contracts to cushion against unfavorable monthly price swings.

Additional Actions and Outlook: Beginning with the first quarter of 2002, Enogex's operations will be reported into four activities: Transportation and Storage, Gathering and Processing, Marketing and Trading and Exploration and Production. During 2002, the Company expects approximately 64 percent of Enogex's earnings before interest and taxes ("EBIT") to be generated by Transportation and Storage due to increased revenues attributable to, among other things, two new long-term transportation contracts with IPPs. Enogex utilizes natural gas storage both to capture price differentials between periods and to support transmission operations. Favorable price differentials are captured by putting physical gas into storage and entering into forward natural gas sales contracts. Storage margins may be optimized by selling physical gas in the cash market to capture short-term opportunities. The Company expects approximately 27 percent of Enogex's EBIT to be generated by Gathering and Processing due to increased revenues, increased fractionation spreads and a better processing environment. The Company's budgets for 2002 assumes a fractionation spread (i.e., the value of liquids after they are processed out of natural gas, less the gas itself) of $1.531 per MMBtu. A $0.10 per MMBtu change in the fractionation spread generally increases or decreases gross margin on revenues by approximately $2.3 million. In 2002, Enogex also began charging pipeline shippers a treating fee for gas that requires processing for delivery into interstate pipelines when the fractionation spreads are not sufficient to cover the cost of processing the gas, as was experienced in 2001. The Company expects approximately eight percent of Enogex's EBIT to be generated by Marketing and Trading through improved gas marketing efforts.

During 2002, the Company expects Enogex to continue to improve its operational performance by reducing the volatility related to natural gas processing. The Company continually monitors the market instruments available to hedge the fractionation spread, however, at this time there are no products available that in management's opinion satisfactorily accomplish this objective. Also, effective January 1, 2002, the Enogex and Transok pipeline systems have been merged to simplify for both Enogex and its customers and administration and operation of maintaining two separate pipelines.

FINANCE AND CONSTRUCTION

The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings and permanent financing. Cash flows from operations have enabled the Company to internally generate the required funds to satisfy construction expenditures.

Management expects that internally generated funds will be adequate over the next three years to meet the Company's anticipated construction expenditures. The primary capital requirements and future contractual obligations for 2001 and as estimated for 2002 through 2005 and beyond are as follows:

(dollars in millions)	**2001**	2002	2003	2004	2005 and Beyond
OG&E construction expenditures including AFUDC.........	**$132.3**	$221.0	$113.0	$116.0	N/A
Enogex construction expenditures and acquisitions......	**83.4**	30.0	37.0	33.0	N/A
Other Operations capital expenditures..................	**9.4**	13.0	11.0	11.0	N/A
Total capital expenditures...................	**225.1**	264.0	161.0	160.0	N/A
Maturities of long-term debt...........................	**12.0**	115.0	14.3	53.0	1,461.6
Capital lease obligations..............................	**1.1**	1.1	1.0	0.9	14.0
Total capital requirements...................	**238.2**	300.1	176.3	213.9	1,475.6
Operating lease obligations............................	**16.6**	18.9	18.2	17.4	126.8
Unconditional purchase obligations:					
Cogeneration capacity payments...................	**191.0**	191.0	163.0	151.0	262.0
Other purchased power capacity payments..........	**23.0**	11.0	N/A	N/A	N/A
Fuel minimum purchase commitments................	**120.0**	134.0	135.0	127.0	654.0
Total unconditional purchase obligations......	**334.0**	336.0	298.0	278.0	916.0
Total capital requirements, operating lease obligations and unconditional purchase obligations............	**588.8**	735.0	492.5	509.3	2,518.4
Amounts recoverable through automatic fuel adjustment clause................................	**(344.3)**	(349.1)	(312.5)	(292.5)	(1,032.9)
Total, net..................................	**$244.5**	$385.9	$180.0	$216.8	$1,485.5

N/A - not applicable

In January 2002, a significant ice storm hit OG&E's service territory. This ice storm inflicted major damage to the transmission and distribution infrastructure. Total expenditures are currently estimated at $136 million. The OG&E 2002 construction expenditures in the above chart include the costs for restoration of the electric utility's system. The Company believes its short-term borrowing capacity is adequate to finance the restoration of the system. The area of damage is within counties that were declared a federal disaster area. OG&E intends to pursue a plan with the OCC to seek recovery of this cost in future rates.

The Company's primary needs for capital are related to replacing or expanding existing facilities in OG&E's electric utility business and to replacing or expanding existing facilities at Enogex. Other capital requirements are primarily related to maturing debt, capital and operating lease obligations and unconditional purchase obligations.

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 electric customers through automatic fuel adjustment clauses. Accordingly, while the cost of fuel related operating leases and the vast majority of unconditional purchase obligations of OG&E may increase capital requirements, such costs are recoverable through automatic fuel adjustment clauses and have little, if any, impact on total net capital requirements. 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 Enogex, which OG&E seeks to recover through the fuel adjustment clause or other tariffs.

The Company's construction program for the next several years does not include additional base-load generating units. Rather, to meet the increased electricity needs of OG&E's electric utility customers during the foreseeable future, OG&E will concentrate on maintaining the reliability and increasing the utilization of existing capacity, increasing demand-side management efforts and, if necessary, purchasing capacity from third parties. OG&E will continue to evaluate these strategies against the construction of additional peaking units or another base-load generating unit. These evaluations will consider, among other things, the amount of capital requirements and the relative cost of fuel supply, compared to other alternatives. Approximately $2.3 million of the Company's construction expenditures budgeted for 2002 are to comply with environmental laws and regulations.

The Company will continue to use short-term borrowings to meet temporary cash requirements. OG&E has the necessary approvals to incur up to $400 million in short-term borrowings at any one time. At December 31, 2001, the Company had in place a line of credit for up to $315 million, with $200 million expiring on January 15, 2002, $15 million expiring on June 26, 2002, and $100 million expiring on January 15, 2004. In January 2002, the Company's $200 million line of credit was renewed for $195 million, with an expiration date of January 19, 2003. Short-term borrowings will consist of some combination of bank borrowings and commercial paper. The Company's ability to access the commercial paper market could be adversely impacted by a commercial paper ratings downgrade. The line of credit contains ratings triggers that require annual fees and borrowing rates to increase if the Company suffers an adverse ratings impact. The impact of a downgrade would result in an increase in the cost of short-term borrowings of approximately five to 20 basis points, but would not result in any defaults or accelerations as a result of the ratings triggers.

The Company continues to evaluate opportunities to enhance shareowner returns and achieve long-term financial objectives through acquisitions of assets that may complement its existing portfolio. Permanent financing could be required for such acquisitions if one was to occur.

The Company's financial results continue to be substantially impacted by the rates OG&E charges customers and the actions of the regulatory bodies that set those rates, the amount of energy used by OG&E's customers, the cost and availability of external financing and the cost of conforming to government regulations.

ENVIRONMENTAL MATTERS

The Company's management believes 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 $44.2 million during 2002, compared to approximately $42.7 million utilized in 2001. Approximately $2.3 million of the Company's construction expenditures budgeted for 2002 are to comply with environmental laws and regulations. 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.

As required by Title IV of the Clean Air Act Amendments of 1990 ("CAAA"), OG&E has completed installation and certification of all required continuous emissions monitors at its generating stations. OG&E submits emissions data quarterly to the Environmental Protection Agency ("EPA") as required by the CAAA. Phase II sulfur dioxide ("SO2") emission requirements affected OG&E beginning in the year 2000. OG&E met the SO2 limits without additional capital expenditures due to OG&E's earlier decision to purchase low sulfur coal. In 2001, OG&E's SO2 emissions were well below the allowable limits.

With respect to the nitrogen oxide ("NOx") regulations of Title IV of the CAAA, OG&E committed to meeting a 0.45 lbs/MMBtu NOx emission level in 1997 on all coal-fired boilers. As a result, OG&E was eligible to exercise its option to extend the effective date of the lower emission requirements from the year 2000 until 2008. OG&E's average NOx emissions from its coal-fired boilers for 2001 was 0.33lbs/MMBtu.

OG&E has submitted all of its required Title V permit applications. As a result of the Title V Program, OG&E paid approximately $0.5 million in fees in 2001.

Other potential air regulations have emerged that could impact OG&E. On December 14, 2000, the EPA announced its decision to regulate mercury emissions from coal-fired utility boilers. Limits on the amount of mercury emitted are expected to be finalized by December 2004, although full compliance by OG&E is not expected to be required until 2008. Depending upon the final regulations implemented, this could result in significant capital and operating expenditures.

In 1997, the EPA finalized revisions to the ambient ozone and particulate standards. However, the standards were challenged in court and the ozone standard was subsequently remanded back to the EPA for further consideration. The EPA appealed the decision to the U.S. Supreme Court and the Supreme Court issued its decision on February 27, 2001. In its decision, the Supreme Court remanded the case to the District of Columbia Court of Appeals, in part, to allow additional challenges to the standards. If the proposed standard is eventually upheld, then it is likely that Tulsa County will fail to meet the new standard for ozone. The EPA has already indicated that in addition to Tulsa County, Muskogee County will also be considered non-attainment because of its impact on Tulsa. If this occurs NOx reductions at OG&E's Muskogee Generating Station could be required. In addition, the EPA projects that Muskogee, Kay, Tulsa and Comanche Counties in Oklahoma would fail to meet the

standard for particulate matter. If reductions are required in Muskogee, Kay and Oklahoma Counties, significant capital expenditures could be required by OG&E.

The EPA also has 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. Sulfates and nitrate aerosols (both emitted from coal-fired boilers) can lead to the degradation of visibility. Under these regulations, it is possible that controls on emission sources hundreds of miles away from the affected area may be required. The EPA has begun the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas. If an impact is determined, then significant capital expenditures could be required for both Sooner and Muskogee Generating Stations.

In 1997, the United States was a signatory to the Kyoto Protocol on global warming. While the Protocol is not likely to be ratified by the U.S. Senate, legislation has been drafted that would limit carbon dioxide emissions. If legislation is passed 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.

OG&E has and will continue to seek new pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2001, OG&E obtained refunds of approximately $211,000 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 reuse of existing materials. Similar savings are anticipated in future years.

OG&E has received approvals to renew its Oklahoma Pollution Discharge Elimination System ("OPDES") permits for all facilities except one, which is awaiting final regulatory action. All of the renewed permits issued to date offer greater operational flexibility than those in the past. In addition, OG&E has made application for a new OPDES permit to cover gas turbine generating units that were constructed at one of its existing plants.

OG&E requested that the State agency responsible for the development of Water Quality Standards remove the agriculture beneficial use classification from one of its cooling water reservoirs. Without removal of this classification, OG&E could be subjected to costly treatment and/or facility reconfiguration requirements. Both the State and EPA have now approved this request.

Enogex, like OG&E, is subject to numerous environmental laws and regulations that affect its operations. See Item 3 "Legal Proceedings" for a description of a recent consent decree and pending notices of violations involving Enogex's operations.

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. One site has been identified as having been contaminated by historical operations. Remedial options based on the future use of this site are being pursued with appropriate regulatory agencies. The cost of these actions has not had and is not anticipated to have a material adverse impact on the Company's consolidated financial position or results of operations.

EMPLOYEES

The Company and its subsidiaries had 3,255 employees at December 31, 2001.

Item 2. Properties.

OG&E owns and operates an interconnected electric production, transmission and distribution system, located in Oklahoma and western Arkansas, which includes eight generating stations with an aggregate capability of 5,732 megawatts. The following table sets forth information with respect to electric generating facilities, all of which are located in Oklahoma:

Station & Unit		Fuel	Year Installed	Unit Capability (Megawatts)	Station Capability (Megawatts)
Seminole	1	Gas	1971	517.0	
	2	Gas	1973	505.0	
	3	Gas	1975	508.0	1,530
Muskogee	3	Gas	1956	149.0	
	4	Coal	1977	515.0	
	5	Coal	1978	514.0	
	6	Coal	1984	502.0	1,680
Sooner	1	Coal	1979	503.0	
	2	Coal	1980	505.0	1,008
Horseshoe	6	Gas	1958	154.0	
Lake	7	Gas	1963	227.0	
	8	Gas	1969	390.0	
	9	Gas	2000	46.0	
	10	Gas	2000	46.0	863
Mustang	1	Gas	1950	55.0	
	2	Gas	1951	51.0	
	3	Gas	1955	115.0	
	4	Gas	1959	248.0	
	5	Gas	1971	65.0	534
Conoco	1	Gas	1991	32.0	
	2	Gas	1991	31.0	63
Enid	1	Gas	1965	11.0	
	2	Gas	1965	10.0	
	3	Gas	1965	11.0	
	4	Gas	1965	12.0	44
Woodward	1	Gas	1963	10.0	10
Total Generating Capability (all stations)					5,732

At December 31, 2001, OG&E's transmission system included: (i) 31 substations with a total capacity of approximately 13.3 million kilo Volt-Amps ("kVA") and approximately 4,002 structure miles of lines in Oklahoma; and (ii) two substations with a total capacity of approximately 1.4 million kVA and approximately 252 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 335 substations with a total capacity of approximately 7.4 million kVA, 22,403 structure miles of overhead lines, 1,783 miles of underground conduit and 7,246 miles of underground conductors in Oklahoma; and (ii) 36 substations with a total capacity of approximately 1.2 million kVA, 1,870 structure miles of overhead lines, 209 miles of underground conduit and 424 miles of underground conductors in Arkansas.

At December 31, 2001, Enogex and its subsidiaries own: (i) approximately 9,700 miles of intrastate transmission and gathering lines in the states of Oklahoma and Texas; (ii) 11 natural gas processing plants with a capacity to process over one Bcfd, all located in Oklahoma; (iii) 75 percent interest in NOARK, which consists of 925 miles of interstate transmission and gathering pipelines, located in eastern Oklahoma and Arkansas; (iv) an 18 billion cubic feet ("Bcf") gas storage field in Oklahoma with a withdrawal capacity of 450 MMcfd; (v) five Bcf of gas storage in Oklahoma with a withdrawal capacity of 400 MMcfd; (vi) an 80 percent interest in NuStar, which includes a 66.67 percent interest in the 110 MMcfd capacity Benedum processing plant, a 100 percent interest in a smaller 30 MMcfd by-pass plant, over 200 miles of gathering pipelines and 52 miles of NGL pipeline, all located in the Permian Basin of west Texas; and (vii) 100 percent of the Belvan Corp., which consists of a natural gas processing plant with a capacity of process 15 MMcfd, a sulfur recovery plant, and an eight mile NGL pipeline, and 344 miles of gathering lines in west Texas. See Note 13 of Notes to Consolidated Financial Statements for a discussion of recent actions concerning Belvan Corp.

During the three years ended December 31, 2001, the Company's gross property, plant and equipment additions approximated $1.1 billion and gross retirements approximated $143.3 million. These additions were provided by internally generated funds from operating cash flows, permanent financing and short-term borrowings. The additions during this three-year period amounted to approximately 23 percent of total property, plant and equipment at December 31, 2001.

Item 3. Legal Proceedings.

In the normal course of business, various lawsuits and claims have risen against the Company. When appropriate, management, after consultation with legal counsel, records an estimate of the probable cost of settlement or other disposition for such matters to the extent not covered by insurance or recoverable through regulated rates.

1. The City of Enid, Oklahoma ("Enid") through its City Council, notified OG&E of its intent to purchase OG&E's electric distribution facilities for Enid and to terminate OG&E's franchise to provide electricity within Enid as of June 26, 1998. On August 22, 1997, the City Council of Enid adopted Ordinance No. 97-30, which in essence granted OG&E a new 25-year franchise subject to approval of the electorate of Enid on November 18, 1997. In October 1997, 18 residents of Enid filed a lawsuit against Enid, OG&E and others in the District Court of Garfield County, State of Oklahoma, Case No. CJ-97-829-01. Plaintiffs seek a declaration holding that (i) the Mayor of Enid and the City Council breached their fiduciary duty to the public and violated Article 10, Section 17 of the Oklahoma Constitution by allegedly "gifting" to OG&E the option to acquire OG&E's electric system when the City Council approved the new franchise by Ordinance No. 97-30; (ii) the subsequent approval of the new franchise by the electorate of the City of Enid at the November 18, 1997, franchise election cannot cure the alleged breach of fiduciary duty or the alleged constitutional violation; (iii) violations of the Oklahoma Open Meetings Act occurred and that such violations render the resolution approving Ordinance No. 97-30 invalid; (iv) OG&E's support of the Enid Citizens' Against the Government

Takeover was improper; (v) OG&E has violated the favored nations clause of the existing franchise; and (vi) the City of Enid and OG&E have violated the competitive bidding requirements found at 11 O.S. 35-201, *et seq.* Plaintiffs seek money damages against the Defendants under 62 O.S. 372 and 373. Plaintiffs allege that the action of the City Council in approving the proposed franchise allowed the option to purchase OG&E's property to be transferred to OG&E for inadequate consideration. Plaintiffs demand judgment for treble the value of the property allegedly wrongfully transferred to OG&E. On October 28, 1997, another resident filed a similar lawsuit against OG&E, Enid and the Garfield County Election Board in the District Court of Garfield County, State of Oklahoma, Case No. CJ-97-852-01. However, Case No. CJ-97-852-01 was dismissed without prejudice in December 1997. On December 8, 1997, OG&E filed a Motion to Dismiss Case No. CJ-97-829-01 for failure to state claims upon which relief may be granted. This motion is currently pending. While the Company cannot predict the precise outcome of this proceeding, the Company believes at the present time that this lawsuit is without merit and intends to vigorously defend this case.

2. United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation (now, OGE Energy Resources Inc.) 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. Plaintiff's action is a qui tam action under the False Claims Act. Jack J. Grynberg, as individual Relator on behalf of the United States Government, Plaintiff, alleges: (i) each of the named Defendants have improperly and intentionally mismeasured gas (both volume and Btu content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as Relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring Defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees. Plaintiff has filed over 70 other cases naming over 300 other defendants in various Federal Courts across the country containing nearly identical allegations.

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, has decided not to intervene in this action or any of the other Grynberg qui tam actions.

On November 16, 1999, the Multidistrict Litigation Panel ("MDL Panel") entered its order 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.

On November 17, 1999, the Company filed a motion to dismiss, seeking: (i) a stay of discovery until after the dispositive motions are resolved; and (ii) dismissal of the complaint on various bases under the Federal Rules of Civil Procedure. A number of other defendants adopted the Company's pleadings or filed similar motions. On December 22, 1999, the Company joined a number of other defendants in filing Defendants' Statement of Points and Authorities regarding discovery issues. Grynberg's responses to all motions to dismiss were filed on January 14, 2000, and the Company's reply and those of other defendants were filed on February 14, 2000. A hearing on the motions to dismiss was held on March 17, 2000. Plaintiffs supplemented their Response on January 11, 2001. The Company filed a

Response to Plaintiffs' Supplement on January 23, 2001. The Court denied the Company's Motion to Dismiss on May 18, 2001.

On April 10, 2000, the MDL Panel transferred another *qui tam case (Quinque Operating Company, et al. v. Enogex Services Corporation, Enogex, Inc., Transok LLC, Transok, Inc., and Oklahoma Gas & Electric Company, et al.) ("Quinque")* to Judge Downes in Wyoming and the MDL Panel consolidated it with this case.

On July 27, 2000, the Department of Justice ("DOJ") filed a Motion to Dismiss certain of Grynberg's claims on the basis Grynberg was not the first to file such *qui tam* allegations. On August 28, 2000, Grynberg filed his Response to the DOJ's Motion. On September 8, 2000, the DOJ filed its Reply. On November 16, 2000, Grynberg filed a Supplement. The DOJ's Motion to Dismiss was heard on February 22, 2001. The Court has not yet ruled on the DOJ's Motion to Dismiss.

3. On September 24, 1999, the Company was served with an Amended Class Action Petition filed in United States District Court, State of Kansas by Quinque Operating Company, on behalf of itself and others, alleging approximately 200 defendants, including OG&E, Enogex and two subsidiaries of Enogex, including Transok, have improperly and intentionally mismeasured gas (both volume and Btu content) purchased from all

lands in the United States except from federal and Indian lands. Plaintiffs claim: (i) underpayment by the Company and all other Defendants of gas royalties claimed to be owed to the Plaintiffs and the punitive class; (ii) breach of contract; (iii) negligence or intentional misrepresentation; (iv) civil conspiracy; (v) fraud; and (vi) breach of fiduciary duty. Plaintiffs seek the following damages: (a) actual damages in excess of $75,000; (b) punitive damages; (c) certification of the class; and (d) injunction to prevent mismeasurement in the future.

On October 5, 1999, the Company filed its Notice with the MDL Panel advising the MDL Panel of a possible tag-along action to the Grynberg *qui tam* actions discussed in Item 3, number 2 above. On April 10, 2000, the MDL Panel transferred this case to Judge Downes in Wyoming and consolidated it with the Grynberg cases above.

On September 8, 2000, Plaintiffs filed a Motion for Expedited Hearing on Motion to Remand. On January 12, 2001, the Court issued its oral order granting Plaintiff's Motion to Remand. The Court is currently reviewing a Motion to Reconsider before sending the Order to the Stevens County Clerk, effectively remanding the case back to the Kansas State Court.

On September 12, 2001, the Company filed a Motion to Dismiss Plaintiffs' Second Amended Petition for failure to state a claim, and included a request for dismissal based on lack of personal jurisdiction. The Reply was filed by the Company on November 2, 2001. Oral argument on the Motion to Dismiss was held on November 29, 2001. The Court has not yet ruled.

A Discovery Planning Conference will be held by the Court on January 13, 2003. Until then, all discovery is stayed except for limited discovery related to Defendants' Motions to Dismiss for lack of personal jurisdiction and discovery related to class certification. The Company has asserted a personal jurisdiction defense.

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, we are unable to comment on any potential exposure to loss of the Company or likely outcome at this time.

4. In April, 2001, Enogex received a Notice of Violation ("NOV") from the Oklahoma Department of Environmental Quality)"ODEQ") regarding potential permitting issues at its Verden Compressor Station, acquired in the Transok acquisition. The NOV related to the operation of a glycol dehydrator and alleged: (1) Enogex had not utilized the proper mechanism to evaluate emissions from the glycol dehydrator; (2) the Facility was subject to the recently promulgated Maximum Achievable Control Technology ("MACT"); (3) failure to install MACT on the dehydrator; (4) deficiencies and/or absence of air quality major source construction/operating permits and periodic reports; and (5) exceedance of certain air quality permit limits. After working closely with the ODEQ to resolve the issues raised in the NOV, the parties finalized a Consent Order on February 4, 2002, pursuant to which Enogex has taken the following actions: (1) installed the required MACT and Best Available Control Technology ("BACT"); (2) filed a Title V operating permit application; (3) conducted performances tests on the control equipment, filed the test results and filed all required periodic reports; and (4) paid a $103,150 penalty on February 6, 2002. Installation of the MACT cost approximately $40,000.

Similar emission and permitting issues relating to glycol dehydration may exist at nine (9) other Enogex facilities. The ODEQ has issued NOV's for these sites and Enogex is working with the ODEQ to attempt to resolve the issues at these sites. The allegations in these NOV's are essentially similar to the allegations contained in the NOV relating to the Verden Compressor Station.

The ODEQ has submitted proposed consent orders relating to four of the sites (Custer Electric Compressor Station, Grandview Compressor Station, Maple Compressor Station, and Thomas Tie Compressor Station). The proposed consent orders would require Enogex to install BACT at a cost ranging from $20,000 to $40,000 per Station, file permits, establish periodic reporting procedures and pay penalties. The penalties proposed by the ODEQ do not exceed $100,000 individually, but in the aggregate total approximately $200,000. Enogex is negotiating with the ODEQ to eliminate or reduce the proposed penalties and to allow Enogex to apply supplemental environmental projects to any penalty amounts assessed for each specific facility.

For the five remaining sites (Clinton Gas Plant, Comanche Tap Gas Processing Plant, Moorewood Compressor Station, South Oakwood Compressor Station and Strong City Compressor Station) the ODEQ and Enogex are currently exchanging information and no specific actions or penalties have been proposed. Enogex expects to resolve the issues at these remaining sites in a manner similar to that proposed above. Enogex believes that the amounts of any penalty or expenditures for supplemental environmental projects will not exceed $100,000 for any single facility but in the aggregate may exceed $100,000.

Enogex continues to monitor its operations to insure compliance with applicable air quality permitting and other environmental requirements.

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

None

Executive Officers of the Registrant.

The following persons were Executive Officers of the Registrant as of March 15, 2002:

Name	Age	Title
Steven E. Moore	55	Chairman of the Board, President and Chief Executive Officer
Al M. Strecker	58	Executive Vice President and Chief Operating Officer
Roger A. Farrell	49	President and Chief Executive Officer - Enogex Inc.
James R. Hatfield	44	Senior Vice President and Chief Financial Officer
Jack T. Coffman	58	Senior Vice President - Power Supply

Melvin D. Bowen, Jr.	60	Vice President - Electric Services
Michael G. Davis	52	Vice President - Process Management
Irma B. Elliott	63	Vice President and Corporate Secretary
Steven R. Gerdes	45	Vice President - Shared Services
David J. Kurtz	40	Vice President - Business Development
Donald R. Rowlett	44	Vice President and Controller
Don L. Young	61	Internal Audit Officer
Eric B. Weekes	50	Treasurer
Gary D. Huneryager	51	Assistant Internal Audit Officer

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Moore, Strecker, Hatfield, Davis, Gerdes, Rowlett, Young, Weekes, Huneryager and Ms. Elliott are also officers of OG&E. Each Officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Stockholders, currently scheduled for May 16, 2002.

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

Name	Business Experience	
Steven E. Moore	1997-Present:	Chairman of the Board, President and Chief Executive Officer
Al M. Strecker	1998-Present:	Executive Vice President and Chief Operating Officer
	1997-1998:	Senior Vice President
Roger A. Farrell	1998-Present:	President and Chief Executive Officer - Enogex Inc.
	1997-1998:	Executive Vice President - Enogex Inc.
	1997:	Vice President - Business Development - Enogex Inc.
James R. Hatfield	2000-Present:	Senior Vice President and Chief Financial Officer
	1999-2000:	Senior Vice President, Chief Financial Officer and Treasurer
	1997-1999:	Vice President and Treasurer
	1997:	Treasurer - OG&E
Jack T. Coffman	1999-Present:	Senior Vice President - Power Supply
	1997-1999:	Vice President - Power Supply
Melvin D. Bowen, Jr.	2002-Present:	Vice President Electric Services
	1997-2002:	Vice President - Power Delivery

Michael G. Davis	2002-Present:	Vice President - Process Management
	1998-2002:	Vice President - Marketing and Customer Care
	1997-1998:	Vice President - Marketing and Customer Services - OG&E
Irma B. Elliott	1997-Present:	Vice President and Corporate Secretary
Steven R. Gerdes	1998-Present:	Vice President - Shared Services
	1997-1998:	Director - Shared Services
	1997:	Manager - Enterprise Support
	1997:	Manager - Purchasing and Material Management - OG&E

David J. Kurtz	1999-Present:	Vice President - Business Development
	1997-1999:	Vice President - Business Development - Enogex Inc.
	1997:	Director - Gas Supply - Enogex Inc.
Donald R. Rowlett	1999-Present:	Vice President and Controller
	1997-1999:	Controller Corporate Accounting
Don L. Young	2001-Present:	Internal Audit Officer
	1997-2001:	Controller Corporate Audits
Eric B. Weekes	2000-Present:	Treasurer
	1997-2000:	Treasurer - Illinois Power and Light
	1997:	Senior Financial Manager - Kraft Foods Inc.

Gary D. Huneryager	2001-Present:	Assistant Internal Audit Officer
	1998-2001:	Service Line Director (Business Process Outsourcing) - Arthur Andersen LLP
	1997-1998:	Chief Financial Officer - The Abbey Group

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters.

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

2000	Dividend Paid	High	Low
First Quarter............................	$0.3325	$ 20.88	$ 16.50
Second Quarter...........................	0.3325	21.25	18.31
Third Quarter............................	0.3325	23.25	18.75
Fourth Quarter...........................	0.3325	24.75	18.94

2001	**Dividend Paid**	**High**	**Low**
First Quarter............................	**$0.3325**	**$ 24.69**	**$ 21.25**
Second Quarter...........................	**0.3325**	**23.77**	**20.80**
Third Quarter............................	**0.3325**	**23.48**	**20.25**
Fourth Quarter...........................	**0.3325**	**23.41**	**20.95**

2002	Dividend Paid	High	Low
First Quarter (through February 28).......	$ ---	$ 23.51	$ 21.28

The number of record holders of Common Stock at February 28, 2002, was 33,748. The book value of the Company's Common Stock at February 28, 2002, was $13.27.

Item 6. Selected Financial Data.

HISTORICAL DATA

	2001	2000	1999	1998	1997
SELECTED FINANCIAL DATA					
(dollars in thousands except for per share data)					
Operating revenues	**$3,182,363**	$3,298,727	$2,172,434	$1,617,737	$1,443,610
Cost of goods sold	**2,266,143**	2,356,160	1,290,608	772,168	673,034
Gross margin on revenues	**916,220**	942,567	881,826	845,569	770,576
Other operating expenses	**638,205**	592,746	543,661	506,112	502,126
Operating income	**278,015**	349,821	338,165	339,457	268,450
Other income (expenses)	**(2,026)**	2,595	480	5,758	5,047
Earnings before interest and taxes	**275,989**	352,416	338,645	345,215	273,497
Interest expense, net	**122,835**	128,876	97,442	70,699	66,495
Income tax expense	**52,583**	76,505	89,944	108,644	74,452
Net income	**100,571**	147,035	151,259	165,872	132,550
Preferred dividend requirements	**---**	---	---	733	2,285
Earnings available for common	**$ 100,571**	$ 147,035	$ 151,259	$ 165,139	$ 130,265
Long-term debt	**$ 1,526,303**	$1,648,523	$1,140,532	$ 935,583	$ 841,924
Total assets	**$ 3,996,592**	$4,319,630	$3,921,334	$2,983,929	$2,765,865
Earnings per average common share	**$ 1.29**	$ 1.89	$ 1.94	$ 2.04	$ 1.61
CAPITALIZATION RATIOS					
Common equity	**40.54%**	39.23%	47.20%	52.72%	52.50%
Cumulative preferred stock	**---**	---	---	---	2.63%
Long-term debt	**59.46%**	60.77%	52.80%	47.28%	44.87%
INTEREST COVERAGES					
Before federal income taxes					
(including AFUDC)	**2.20X**	2.66X	3.39X	4.84X	4.11X
(excluding AFUDC)	**2.19X**	2.64X	3.38X	4.82X	4.10X
After federal income taxes					
(including AFUDC)	**1.79X**	2.09X	2.50X	3.31X	2.98X
(excluding AFUDC)	**1.78X**	2.07X	2.49X	3.30X	2.97X

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

Management's Discussion and Analysis

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 in the south central United States. The Company conducts these activities through two business segments, the electric utility and the energy supply 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 the jurisdiction of the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC").

The energy supply segment produces, gathers, processes, transports, markets and stores natural gas and produces, transports, and markets natural gas liquids. These operations are conducted primarily through Enogex Inc. and its subsidiaries ("Enogex"). Enogex is also involved in commodity sales and services related to natural gas and electric power, primarily through its subsidiary, OGE Energy Resources Inc. ("OERI").

The Company's business strategy is to assemble a portfolio of assets, people, skills and customers that create optimal value from the convergence occurring in the electricity and natural gas markets. The Company believes its converged portfolio is well positioned to take advantage of opportunities in the south central United States.

OG&E continues to substantially impact the financial results and condition of the Company. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area, which is the second largest market and an area of high growth in that state. OG&E is expected to grow moderately, consistent with historic trends. Expansion will primarily result from continued economic growth in its service territory. The citizens of Oklahoma recently passed a "right to work" referendum. This action along with other initiatives are intended to enhance the state's ability to promote itself as a business-friendly location.

Enogex owns and operates the tenth largest natural gas pipeline system in the United States in terms of miles of pipe in service. Enogex has a significant investment in natural gas gathering, processing, transmission and storage in the major gas producing basins of Oklahoma, as well as gathering and processing operations in west Texas. Enogex also has a seventy-five percent interest in the NOARK Pipeline System Limited Partnership, which owns the Ozark Gas Transmission System ("Ozark"). Ozark is a FERC regulated interstate pipeline that is operated by Enogex, and is located from southeast Oklahoma through Arkansas and terminates just across the state line in southeast Missouri. Enogex, through its affiliate OERI, markets energy products, including natural gas and electric power, and provides energy related services for corporate commodity price risk management and energy forward price evaluations. Enogex also has investments in exploration and production of natural gas and oil with properties located primarily in Michigan and Oklahoma.

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including particularly the information under the caption "2002 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", "estimate", "objective", "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 their impact on capital expenditures; 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; state and federal legislative and regulatory decisions 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; and the other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission.

OVERVIEW

The following discussion and analysis present factors that had a material effect on the operations and financial position of the Company and its subsidiaries during the last three years and should be read in conjunction with the Consolidated Financial Statements and Notes thereto. Trends and contingencies of a material nature are discussed to the extent known and considered relevant.

The Company reported earnings of $1.29 a share in 2001, a 31.7 percent decrease from $1.89 a share in 2000. The reduced earnings reflect lower revenues at Enogex and increased operating expense at both OG&E and Enogex.

OG&E contributed $1.55 in earnings per share in 2001, down from $1.83 in 2000. The decrease in earnings was primarily attributable to lower kilowatt-hour sales to OG&E's electric customers ("system sales") due to milder weather and higher operating and maintenance expense. As described in more detail below, revenues at OG&E were also partially offset by state regulatory actions that reduced recoveries under rate riders previously established by the OCC.

Enogex operations resulted in a loss of $0.06 per share in 2001, down from earnings of $0.25 per share in 2000. As described below, the loss at Enogex was attributable primarily to poor fractionation spreads in its gas processing business. Enogex earnings also were adversely affected by lower margins in its energy marketing and trading business compared to 2000.

The results on a stand-alone basis of the Company (i.e., as a holding company), which has expenses but no revenues, reflect a loss of $0.20 per share in 2001, compared to a loss of $0.19 per share in 2000. These results are primarily due to interest and tax expenses.

The Company reported earnings of $1.89 a share in 2000, a 2.6 percent decrease from $1.94 a share in 1999. Record revenues of $3.3 billion were offset by higher operating and maintenance expenses and increased interest expense.

Enogex contributed $0.25 in earnings per share in 2000, down from $0.28 in 1999. Revenues increased at Enogex due to higher commodity prices and increased gas marketing volumes, as well as greater natural gas transportation and processing volumes reflecting the full year impact of the Tejas Transok Holding, L.L.C. and subsidiaries ("Transok") acquisition in mid 1999. The higher revenues at

Enogex were offset by higher gas and electricity purchased for resale, operation and maintenance (including a $25 million increase in under-recovered pipeline fuel expense) and interest expenses. The holding company incurred increased interest expenses, which resulted in a loss of $0.19 per share in 2000, as compared to a loss of $0.12 per share in 1999.

The reduction in earnings in 2000 was partially offset by higher earnings at OG&E, which contributed $1.83 in earnings per share in 2000, up from $1.78 in 1999. The increase in OG&E's earnings was primarily attributable to higher revenues from system sales due to more favorable weather in the last six months of 2000. Revenue also increased due to the recovery of higher fuel costs. The increase in revenues was only partially offset by state regulatory action that changed the Generation Efficiency Performance Rider ("GEP Rider") and implemented the Acquisition Premium Credit Rider ("APC Rider").

The dividend payout ratio (expressed as a percentage of earnings available for common shareholders) was 103 percent in 2001 as compared to 70 percent in 2000. The Company's desired dividend payout ratio is 75 percent or below based on the current business environment. Future dividend action will be dependent primarily on two factors. First, the appropriate payout ratio will be determined by the pace and structure of the deregulation of the electric utility business. Second, the payout rates will continue to be based on current and anticipated operating results. Based on current assessment of these as well as other factors, management believes the current dividend level of $1.33 will be maintained; however, decisions regarding the payment level of dividends will be made by the board of directors from time to time based on results of operations, financial position, cash flows and other relevant factors.

In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of OG&E. OG&E's rates had last been formally reviewed in 1995. In the filing, the Staff requested that OG&E submit information in accordance with OCC minimum standard filing requirements by January 28, 2002, for a test year ending September 30, 2001. On January 28, 2002, OG&E filed its response requesting a $22 million annual rate increase. OG&E's filing also outlined several new customer programs and offered not to seek another increase for at least three years. It has been 16 years since OG&E requested a rate increase. A final order in the OG&E rate case is not expected before summer 2002. At this time, management cannot predict the outcome of this rate case or the impact on its consolidated financial position or results of operation. This development is described in more detail in Note 11 of Notes to Consolidated Financial Statements.

The Company's regulated utility business has been and will continue to be affected by competitive changes to the utility industry. Significant changes already have occurred in the wholesale electric markets at the federal level and significant changes are expected at the retail level in the states served by OG&E. In Oklahoma, legislation was passed in April 1997 to provide for the orderly restructuring of the electric industry with the goal to provide retail customers with the ability to choose their electric suppliers by July 1, 2002. In May 2001, the Oklahoma Legislature passed legislation postponing the scheduled start date for customer choice from July 1, 2002 until at least 2003. In addition to postponing the date for customer choice, the legislation calls for a nine-member task force to further study the issues surrounding deregulation. In April 1999, Arkansas passed a law calling for restructuring of the electric utility industry at the retail level. The law initially targeted customer choice of electricity providers by January 1, 2002, but the law was amended to delay customer choice until October 1, 2003. These developments at the federal and state levels are described in more detail below under "Electric Competition; Regulations."

On July 1, 1999, the Company, through Enogex, completed the largest acquisition in its history by acquiring Transok, a gatherer, processor and transporter of natural gas in Oklahoma and Texas. Transok's principal assets included approximately 4,900 miles of natural gas pipelines in Oklahoma and

Texas with a capacity of approximately 2.6 billion cubic feet per day and 18 billion cubic feet of underground natural gas storage. Transok assets also included nine gas processing plants. Enogex purchased Transok for $710.3 million, which included the assumption of $173 million of long-term debt.

2002 Outlook

The Company expects that earnings in 2002 will be between $1.60 and $1.80 per share, assuming normal weather in the electric utility service area. The Company anticipates a contribution of approximately $1.60 per share from OG&E, $0.30 per share from Enogex and ($0.20) per share from results on a stand-alone basis as a holding company. The Company also expects to maintain its annual dividend of $1.33 per share.

The foregoing estimate of earnings per share assumes OG&E's revenues will increase primarily due to growth in the number of customers and usage by existing customers and a return to more normal weather. Revenues will be partially offset by the expiration of the GEP Rider in mid 2002.

On January 28, 2002, the Company filed documentation with the OCC requesting a $22 million annual rate increase. Approximately $10 million of this total relates to enhanced security as a result of the September 11, 2001 terrorist attacks and approximately $12 million of this total relates to increased capacity needs and reliability upgrades. The Company's filing reflected that final testimony in support of the enhanced security request would be filed in late April 2002. The OCC Staff determined that since testimony regarding enhanced security would not be available until after the January 28, 2002, deadline for the OG&E filing, the request for recovery of enhanced security costs should be made in a separate filing. The Company's filing also outlined several new customer programs and offered not to seek another rate increase for at least three years. A final order in this case is not expected before summer 2002. The 2002 earnings outlook for OG&E does not take into account any changes in rates that may result from this proceeding.

During 2002 and without regard to the ice storm detailed below, the Company expects OG&E's operating and maintenance expense to remain relatively flat at the 2001 level with increased property and casualty insurance premiums largely as a result of the September 11, 2001 terrorist attacks being offset by lower bad debt expense.

In January 2002, a significant ice storm hit OG&E's service territory. This ice storm inflicted major damage to the transmission and distribution infrastructure. Total expenditures are currently estimated at $136 million. Based on current estimates, the vast majority of these expenditures for restoration of the utility's system will be capitalized as part of the utility's plant. The Company believes that the capital costs will be considered in the pending rate case. The remaining costs will be deferred pending regulatory approval of a recovery plan. The Company's earnings estimates for 2002 do not include any of the costs associated with the ice storm.

Beginning with the first quarter of 2002, Enogex's operations will be reported into four activities: Transportation and Storage, Gathering and Processing, Marketing and Trading and Exploration and Production. During 2002, the Company expects approximately 64 percent of Enogex's earnings before interest and taxes ("EBIT") to be generated by Transportation and Storage due to increased revenues attributable to, among other things, two new long-term transportation contracts with independent power producers. Enogex utilizes natural gas storage both to capture price differentials between periods and to support transmission operations. Favorable price differentials are captured by putting physical gas into storage and entering into forward natural gas sales contracts. Storage margins may be optimized by selling physical gas in the cash market to capture short-term opportunities. The Company expects approximately 27 percent of Enogex's EBIT to be generated by Gathering and

Processing due to increased revenues, increased fractionation spreads and a better processing environment. The Company's earnings estimate for 2002 assumes a fractionation spread (i.e., the value of liquids after they are processed out of natural gas, less the gas itself) of $1.531 per MMBtu. A $0.10 per MMBtu change in the fractionation spread generally increases or decreases gross margin on revenues by approximately $2.3 million. In 2002, Enogex also began charging pipeline shippers a treating fee for gas that requires processing for delivery into interstate pipelines when the fractionation spreads are not sufficient to cover the cost of processing the gas, as was experienced in 2001. The Company expects approximately eight percent of Enogex's EBIT to be generated by Marketing and Trading through improved gas marketing efforts.

During 2002, the Company expects Enogex to continue to improve its operational performance by reducing the volatility related to natural gas processing. The Company continually monitors the market instruments available to hedge the fractionation spread, however, at this time there are no products available that in management's opinion satisfactorily accomplish this objective. Also, effective January 1, 2002, the Enogex and Transok pipeline systems have been merged to simplify for both Enogex and its customers the administration and operation of maintaining two separate pipelines.

RESULTS OF OPERATIONS

				Percent Change From Prior Year	
(thousands except per share amounts)	**2001**	2000	1999	2001	2000
Operating income	**$ 278,015**	$ 349,821	$ 338,165	(20.5)	3.4
Earnings before interest and taxes	**$ 275,989**	$ 352,416	$ 338,645	(21.7)	4.1
Earnings available for common stock	**$ 100,571**	$ 147,035	$ 151,259	(31.6)	(2.8)
Average shares outstanding	**77,929**	77,864	77,916	0.1	(0.1)
Earnings per average common share	**$ 1.29**	$ 1.89	$ 1.94	(31.7)	(2.6)
Dividends paid per share	**$ 1.33**	$ 1.33	$ 1.33	---	---

In reviewing its operating results, the Company believes that it is appropriate to focus on operating income and EBIT as reported on its Consolidated Statements of Income. Operating income for 2001 was $278.0 million compared to $349.8 million in 2000 and $338.2 million in 1999. EBIT were $276.0 million, $352.4 million and $338.6 million for 2001, 2000 and 1999, respectively. The only difference between operating income and EBIT is the inclusion in EBIT of certain minor non-operating activities. EBIT is summarized in the following table and is discussed by business segment thereafter.

EBIT by Business Segment

(dollars in thousands)	**2001**	2000	1999
OG&E	**$ 234,177**	$ 268,393	$ 268,235
Enogex	**42,328**	84,035	73,251
Other operations	**(516)**	(12)	(2,841)
Consolidated EBIT	**$ 275,989**	$ 352,416	$ 338,645

Other operations primarily include unallocated corporate expenses. The following EBIT by business segment analysis includes intercompany transactions that are eliminated in the Consolidated Financial Statements.

OG&E

(dollars in thousands)	**2001**	2000	1999
Operating revenues	**$ 1,456,802**	$ 1,453,585	$ 1,286,844
Fuel	**485,834**	489,049	350,814
Purchased power	**280,657**	263,328	249,203
Gross margin on revenues	**690,311**	701,208	686,827
Other operating expenses	**453,671**	430,070	417,263
Operating income	**236,640**	271,138	269,564
Other income (expenses), net	**(2,463)**	(2,745)	(1,329)
EBIT	**$ 234,177**	$ 268,393	$ 268,235
System sales - MWH (a)	**24,518,170**	25,001,686	23,468,130
Off-system sales - MWH	**422,619**	256,358	374,027
Total sales - MWH	**24,940,789**	25,258,044	23,842,157

(a) Megawatt-hours

OG&E's EBIT decreased approximately $34.2 million in 2001 compared to 2000. The decrease in EBIT was primarily attributable to lower system sales due to milder weather and to higher operating and maintenance expense.

Gross margin on revenues decreased approximately $10.9 million. Milder than normal weather accounted for about $9.8 million of the decrease in gross margin. OG&E system sales decreased by approximately 484,000 megawatt-hours or 1.9 percent. Cooling degree days and heating degree days were approximately 5.1 percent and 5.3 percent below 2000 levels, respectively. Lower recoveries under the GEP Rider decreased gross margin by approximately $4.0 million when compared to 2000. The lower level of natural gas transportation cost that OG&E was allowed to recover from system customers in 2001 decreased gross margin approximately $0.9 million and $1.5 million as a result of the APC Rider, and the Gas Transportation Adjustment Credit Rider ("GTAC Rider"), respectively. Gross margin on revenues was also reduced by $3.8 million due to a return of over recovered fuel costs to Arkansas customers through that state's automatic fuel adjustment clause. See Note 11 of Notes to Consolidated Financial Statements for a more detailed discussion of these matters. The decreased margin was partially offset by growth in the number of customers and growth in the consumption of existing customers of approximately $9.3 million. Also, while the volume of sales to other utilities and power marketers ("off-system sales") increased, these sales are at lower prices and margins and increased revenues by less than $30,000.

Cost of goods sold for OG&E consists of cost of fuel used in electric generation and purchased power. 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 2001, OG&E's fuel mix was 73 percent coal and 27 percent natural gas. Although fuel consumed was down in 2001, the average cost of fuel per kwh increased 1.0 percent.

OG&E's purchased power costs increased $17.3 million or 6.6 percent in 2001 primarily due to an increase in capacity purchases under a wholesale purchase contract that OG&E maintains with Southwestern Public Service Corp., a 5.8 percent increase in the cost of purchased energy per kwh and a 1.9 percent increase in total energy purchased.

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 electric customers through automatic fuel adjustment clauses. Accordingly, while variances in the cost of fuel and purchased power costs may increase operating revenues, such variances have little, if any, impact on gross margin. 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 Enogex, which OG&E seeks to recover through the fuel adjustment clause or other tariffs. See Note 11 of Notes to Consolidated Financial Statements.

Other operating expenses include operating and maintenance expense, depreciation and amortization, and taxes other than income. OG&E's operating and maintenance expense increased approximately $19.9 million in 2001. Employee pension and benefit costs were up approximately $9.7 million. Pension expense increased primarily due to lower than forecasted returns on assets in the pension trust and the effect of lower discount rates used to measure the accumulated pension obligation. The general upward trend in medical costs also contributed to the increase in employee benefit costs. Bad debt expense increased by approximately $11.6 million. Higher than normal bills driven by high natural gas prices early in the year, customer cut-off moratoriums imposed during high temperature periods this summer and the general slow down in the economy all contributed to these increases. The use of contractors to supplement the Company's own crews to restore customers power after a major ice storm at the beginning of 2001 and a major wind storm in the early summer added approximately $5.9 million to operating and maintenance expenses. The increased operating and maintenance expenses were partially offset by a decrease in miscellaneous expenses and an increase in the amount of certain expenses capitalized as part of electric plant.

Depreciation and amortization for OG&E were $2.5 million higher than in 2000 and reflect higher levels of plant in service. Taxes other than income taxes increased $1.2 million in 2001, reflecting increased ad valorem taxes.

OG&E's EBIT increased approximately $158,000 in 2000 compared to 1999. The increase in OG&E's EBIT was primarily attributable to higher revenues from system sales due to more favorable weather in the last six months of 2000. Revenue also increased due to the recovery of higher fuel costs. The increase in revenues was only partially offset by state regulatory actions that changed the GEP Rider and implemented the APC Rider.

In 2000, OG&E's gross margin increased approximately $14.4 million or two percent over the 1999 level, primarily attributable to warmer weather in the third quarter and colder weather in the fourth quarter in OG&E's electric service area. The increased gross margin from system sales was partially offset by a decrease in gross margin that resulted from a 53.6 percent decrease in revenue from off-system sales. The decline in gross margin off-system sales resulted from a reduction in both volumes and prices. In 2000, OG&E gross margins were also adversely affected by the actions of the OCC in lowering recoveries by $10.9 million under the GEP Rider and implementing the APC Rider, which reduced revenues by $10.2 million. OG&E's revenues in 2000 also were affected by a $2.3 million annual reduction of its rates in Arkansas, which became effective in August 1999.

Cost of goods sold for OG&E increased $152 million in 2000, reflecting increased cost of fuel used in electric generation and increased purchased power costs. Fuel costs increased $138.2 million or 39.4 percent in 2000, primarily due to a 29.9 percent increase in the average cost of fuel burned for generation of electricity and a 7.1 percent increase in total energy generated.

During 2000, purchased power costs increased $14.1 million or 5.7 percent due to a 9.5 percent increase in the cost of purchased energy per kwh, which offset a 4.3 percent reduction in total energy purchased.

OG&E's operating and maintenance expense increased approximately $14 million in 2000. This increase was primarily attributable to higher employee benefit costs and higher labor costs. Depreciation and amortization decreased $1.8 million in 2000, reflecting certain power plant units becoming fully depreciated during the year. Taxes other than income increased $0.6 million due to higher ad valorem taxes.

Enogex

(dollars in thousands)	**2001**	2000	1999
Operating revenues	**$1,767,734**	$2,111,600	$1,086,027
Gas and electricity purchased for resale	**1,396,230**	1,687,107	831,309
Natural gas purchases - other	**145,595**	183,134	59,797
Gross margin on revenues	**225,909**	241,359	194,921
Other operating expenses	**184,439**	162,350	123,808
Operating income	**41,470**	79,009	71,113
Other income (expenses), net	**858**	5,026	2,138
EBIT	**$ 42,328**	$ 84,035	$ 73,251
Physical System Supply - MMcfd (a)	**1,752**	2,079	1,324
Natural gas processed - MMcfd	**733**	808	576
Natural gas liquids sold - 000 gallons (b)	**569,018**	656,303	413,765
Average sales price per gallon	**$ 0.456**	$ 0.518	$ 0.307
Fractionation spread per MMBtu (c)	**$ 1.041**	$ 2.232	$ 1.764
Natural gas marketed - Bbtu (d)	**280,660**	434,577	294,179
Average sales price per Bbtu	**$ 4.403**	$ 3.960	$ 2.299
Power marketed - MWH	**1,226,845**	1,070,334	1,954,621
Average sales price per MWH	**$ 45.180**	$ 46.530	$ 32.990
Natural gas produced - Mmcfe (e)	**5,360**	8,425	10,291
Average sales price per Mcfe (f), net of hedging	**$ 4.097**	$ 3.205	$ 2.480

(a) Million cubic feet per day.
(b) Thousand gallons.
(c) Million British thermal units.
(d) Billion British thermal units.
(e) Million cubic feet equivalent.
(f) Thousand cubic feet equivalent.

Enogex's EBIT for 2001 was $42.3 million, which was $41.7 million or 50 percent less than in 2000. This decline was primarily due to unfavorable market conditions in natural gas processing.

During 2001, the EBIT contribution for the processing group of Enogex dropped from a record level of $68.3 million in 2000, to a loss of $0.2 million. This reduction was attributable to poor fractionation spreads in 2001, which resulted in lower gross margins for natural gas processing. Fractionation spreads are the value of liquids after they are processed out of natural gas, less the price of the gas itself. During the first quarter of 2001, these spreads were negative. A significant percentage of Enogex's volumes were processed under "keep whole" arrangements. Under these arrangements, and in order to keep its shippers whole on a Btu basis, Enogex was required to replace the Btu value of the liquids with natural gas at market prices. In order to minimize the impact of these negative fractionation spreads, ethane and propane were rejected whenever possible. As a result, overall production in 2001 was down 87 million gallons from the 2000 level. The average fractionation spread realized in 2001 was $1.041 per MMBtu compared to $2.232 per MMBtu in 2000. For planning purposes Enogex uses a historical average fractionation spread of approximately

$1.530 per MMBtu. Also included in the processing margin is a $6.0 million write-down for the impairment of certain processing assets that have been identified as being non-core to Enogex's operations. It is anticipated that these assets will be sold by mid 2002.

Improved margins in the gathering and transmission group of Enogex for 2001 offset a portion of the reduced margins from processing. During 2001, the gathering and transportation pipeline and storage facilities contributed $38.6 million, or 91.2 percent of the Enogex EBIT, which was an increase of $40.0 million from the 2000 results. This can be directly attributed to efforts by Enogex in 2001 to resolve the under-recovery of pipeline system fuel expenses that was reported with the fourth quarter 2000 results. Enogex filed for fuel-recovery rate adjustments with the FERC and the new rates became effective on February 1, 2001. The impact of the filing enabled Enogex to significantly improve the recovery of pipeline system fuel expenses for the remainder of the year and in the future. During 2001, this increased fuel recovery improved the pipeline margin by approximately $22 million. Also contributing to the increased margin in the gathering and transmission group were a $15.6 million increase in gas storage margins and a $12.6 million increase in transportation revenues. Partially offsetting these increases to EBIT were approximately $11.6 million of increased operating and maintenance and other miscellaneous expense items.

The margin from exploration and production was $8.7 million in 2001, which is $3.0 million, or 25.4 percent less than the 2000 results. Although prices were up approximately 27 percent during 2001, the volumes produced were down by 36 percent. The production decrease in 2001 is primarily attributable to the sale of working interests in 2000 for oil and gas properties located in Texas and Utah, along with a normal production decline curve. These property sales also contributed approximately $2.1 million to the 2000 Enogex EBIT from exploration and production. The 2000 asset sales were part of a strategy to focus on exploration and production assets close to the physical gathering and transportation assets.

OERI's marketing and trading activities contributed a loss of $4.8 million to Enogex's EBIT for 2001, compared to a $5.4 million positive contribution in 2000. This decline of approximately $10.2 million was due to the inability to generate natural gas, crude oil and electric power trading margins sufficient to cover the cost of operations. OERI's trading activities are conducted throughout the year subject to a $4 million annual trading loss limit. The daily loss exposure is measured using value at risk and other quantitative risk measurement techniques. Accordingly, the trading operations of OERI should not significantly contribute adversely to EBIT.

Enogex depreciation and amortization increased $1.5 million in 2001 reflecting higher levels of plant in service. Taxes other than income taxes increased $1.0 million due to higher ad valorem taxes.

Enogex's EBIT for 2000 was $84.0 million, which was an increase of $10.8 million or 14.7 percent over 1999. This increase was primarily due to strong market conditions in natural gas processing and greater natural gas transportation and processing volumes reflecting the full year impact of the acquisition of Transok in mid 1999. These increases were partially offset by higher operation and maintenance and other expenses, including a $25 million increase in under-recovered pipeline system fuel expense.

During 2000, the EBIT contribution for the processing group of Enogex improved by $64.5 million to reach a record level of $68.3 million. This increase was attributable to strong fractionation spreads in 2000, as well as a significant increase in natural gas liquids sold. The average fractionation spread realized in 2000 was $2.232 per MMBtu compared to $1.764 per MMBtu in 1999. In 2000, natural gas liquids sold increased 239 million gallons (or 56.6 percent) to 662 million gallons. The $73.8 million improvement in gross margin was reduced by higher operation and maintenance expenses. The increases in gas liquids sold and expenses were both due primarily to the full year impact of the Transok acquisition.

Lower margins in the gathering and transmission group of Enogex for 2000 offset a portion of the record margins from processing. During 2000, the gathering and transportation pipeline and storage facilities reported negative EBIT of $1.4 million, which was a decrease of $57.3 million from the 1999 results. This decline is due partially to a $25.0 million increase in under-recovered pipeline system fuel expense. Also contributing to the decline in EBIT was a $25.2 million increase in operation and maintenance expenses primarily due to the full year impact of the Transok acquisition. In addition to increased fuel and other expenses, storage margins declined to $2.7 million from $9.1 million in 1999. These unfavorable variances were partially offset by a $15.6 million increase in transportation revenues.

EBIT from the exploration and production group was $11.7 million in 2000, which is $3.0 million, or 35.0 percent more than the 1999 results. Although volumes produced decreased by 18.1 percent during 2000, prices increased by 29.2 percent. The production decrease in 2000 is primarily attributable to the sale of working interests in late 2000 for oil and gas properties located in Texas and Utah, along with a normal production decline curve. These property sales also contributed approximately $2.1 million to the 2000 Enogex EBIT from exploration and production. The 2000 asset sales were part of a strategy to focus on exploration and production assets close to the physical gathering and transportation assets.

OERI's marketing and trading activities contributed $5.4 million to Enogex's EBIT for 2000, compared to a $4.9 million contribution in 1999. This improvement of $0.5 million was due primarily to increased natural gas marketed.

Enogex depreciation and amortization increased $10.6 million in 2000 and taxes other than income taxes increased $6.0 million. Both increases reflect the full year impact of the acquisition of Transok in mid 1999.

LIQUIDITY AND CAPITAL RESOURCES

The primary capital requirements and future contractual obligations for 2001 and as estimated for 2002 through 2005, and beyond are as follows:

(dollars in millions)	**2001**	2002	2003	2004	2005 and Beyond
OG&E construction expenditures including AFUDC	**$ 132.3**	$ 221.0	$ 113.0	$ 116.0	N/A
Enogex construction expenditures and acquisitions	**83.4**	30.0	37.0	33.0	N/A
Other Operations capital expenditures	**9.4**	13.0	11.0	11.0	N/A
Total capital expenditures	**225.1**	264.0	161.0	160.0	N/A
Maturities of long-term debt	**12.0**	115.0	14.3	53.0	1,461.6
Capital lease obligations	**1.1**	1.1	1.0	0.9	14.0
Total capital requirements	**238.2**	380.1	176.3	213.9	1,475.6
Operating lease obligations	**16.6**	18.9	18.2	17.4	126.8

Unconditional purchase obligations:					
Cogeneration capacity payments	**191.0**	191.0	163.0	151.0	262.0
Other purchased power capacity payments	**23.0**	11.0	N/A	N/A	N/A
Fuel minimum purchase commitments	**120.0**	134.0	135.0	127.0	654.0
Total unconditional purchase obligations	**334.0**	336.0	298.0	278.0	916.0
Total capital requirements, operating lease obligations and unconditional purchase obligations	**588.8**	735.0	492.5	509.3	2,518.4
Amounts recoverable through automatic fuel adjustment clause	**(344.3)**	(349.1)	(312.5)	(292.5)	(1,032.9)
Total, net	**$ 244.5**	$ 385.9	$ 180.0	$ 216.8	$ 1,485.5

N/A - not applicable

In January 2002, a significant ice storm hit the OG&E service territory. This ice storm inflicted major damage to the transmission and distribution infrastructure. Total expenditures are currently estimated at $136 million. The OG&E 2002 construction expenditures in the above chart include the costs for restoration of the electric utility's system. The Company believes its short-term borrowing capacity is adequate to finance the restoration of the system. The area of damage is within counties that were declared a federal disaster area. OG&E intends to pursue a plan with the OCC to seek recovery of this cost in future rates.

During 1996, OG&E completed negotiations and contracted with Central Oklahoma Oil and Gas Corp. ("COOG") for gas storage service. In July 1997, COOG obtained permanent financing and issued

a note in the amount of $49.5 million. In connection with the permanent financing, the Company entered into a note purchase agreement, where it has agreed, upon the occurrence of a monetary default by COOG on its permanent financing, to purchase COOG's note at a price equal to the unpaid principal and interest under the COOG note. See Note 10 of Notes to Consolidated Financial Statements for more detailed discussion of these matters.

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 at Enogex. Other capital requirements are primarily related to maturing debt, capital and operating lease obligations and unconditional purchase obligations. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings and permanent financings.

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 electric customers through automatic fuel adjustment clauses. Accordingly, while the cost of fuel related operating leases and the vast majority of unconditional purchase obligations of OG&E may increase capital requirements, such costs are recoverable through automatic fuel adjustment clauses and have little, if any, impact on total-net capital requirements. 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 Enogex, which OG&E seeks to recover through the fuel adjustment clause or other tariffs. See Note 11 of Notes to Consolidated Financial Statements.

2001 Capital Requirements and Financing Activities

Capital requirements were $238.2 million in 2001. Approximately $3.3 million of the 2001 capital requirements were to comply with environmental regulations. This compares to capital requirements of $354.6 million in 2000, of which $4.4 million was to comply with environmental regulations. During 2001, the Company's sources of capital were internally generated funds from operating cash flows and short-term borrowings. The decreases in accounts receivable and accounts payable, in 2001, are reflective of decreased levels of activity by the Enogex marketing unit and also reflective of the decreases in the cost of natural gas at both OG&E and Enogex.

Short-term borrowings were used during 2001 to meet temporary cash requirements. At December 31, 2001, the Company had outstanding short-term borrowings of $115.0 million.

On January 10, 2001, Enogex retired $5 million principal amount of 7.75 percent medium-term notes due April 24, 2023. On August 8, 2001, Enogex retired $4.75 million principal amount of 7.00 percent medium-term notes due December 1, 2004. This debt had been assumed as part of the Transok acquisition.

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB 133" and SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities". SFAS No. 133 requires the Company to record all derivatives on the balance sheet at fair value. Changes in the fair value of derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, must be recognized as a derivative fair value gain or loss in the income statement. Changes in fair value of effective fair value hedges are recorded in price risk management in the accompanying Consolidated Balance Sheets, with a corresponding net change in the hedged asset or liability. Changes in fair value of effective cash flow hedges are recorded as a

component of Accumulated Other Comprehensive Income, which is later reclassified to earnings when the hedged transaction occurs. Physical delivery contracts which are deemed to be normal purchases or normal sales are not accounted for as derivatives.

The Company accounted for adoption of SFAS No. 133 on January 1, 2001, by recording a cumulative effect transition adjustment debit to Accumulated Other Comprehensive Income of approximately $26.9 million ($16.5 million net of tax). This unrealized loss was related to the derivative fair value of qualifying cash flow hedges as of the date of adoption and was reclassified to earnings as the related hedged transactions occurred. As of December 31, 2001, this amount had been reclassified to earnings. However, the initial unrealized loss was offset by subsequent gain on these qualifying cash flow hedges of approximately $21.4 million ($13.1 million net of tax). The Company also recorded a gain, included in Operating Revenues, related to the ineffective portion of hedge derivatives, for production hedges, of $4.7 million ($3.0 million net of tax) for 2001, resulting in a loss of only approximately $0.8 million ($0.4 million net of tax).

During March 2001, the Company entered into two separate interest rate swap agreements: (i) OG&E entered into an interest rate swap agreement to convert $110 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) effective July 15, 2001, Enogex entered into an interest rate swap agreement to convert $200 million of 8.125 percent fixed rate debt due, January 15, 2010, to a variable rate based on LIBOR. These interest rate swaps qualified as fair value hedges under SFAS No. 133 and meet all requirements for a determination that there was no ineffective portion as allowed under the shortcut method under SFAS No. 133. On April 6, 2001, the Company entered into a one-year interest rate swap agreement to lock in a fixed rate of 4.41 percent, effective April 10, 2001, on $140 million of variable rate short-term debt. This interest rate swap initially qualified for hedge accounting treatment as a cash flow hedge under SFAS No. 133. However, due to unexpected changes in the level of commercial paper issued during the third quarter, hedge accounting treatment under SFAS No. 133 was discontinued as of July 1, 2001, and all subsequent changes in the market value of the swap are being recorded as interest expense. The objective of these interest rate swaps was to achieve a lower cost of debt and raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standard and to reduce exposure to short-term interest rate volatility associated with the Company's commercial paper program.

Future Capital Requirements

The Company's construction program for the next several years does not include additional base-load generating units. Rather, to meet the increased electricity needs of OG&E's electric utility customers during the foreseeable future, OG&E will concentrate on maintaining the reliability and increasing the utilization of existing capacity, increasing demand-side management efforts and, if necessary, purchasing capacity from third parties. OG&E will continue to evaluate these strategies against the construction of additional peaking units or another base-load generating unit. These evaluations will consider, among other things, the amount of capital requirements and the relative cost of fuel supply, compared to other alternatives. Approximately $2.3 million of the Company's construction expenditures budgeted for 2002 are to comply with environmental laws and regulations.

As described above, a significant ice storm hit the OG&E service territory in January 2002. This ice storm inflicted major damage to the transmission and distribution infrastructure. Capital expenditures related to this event are currently estimated to be approximately $120 million. The Company believes its short-term borrowing capacity is adequate to finance the restoration of the system. OG&E intends to pursue a plan with the OCC to seek recovery of this cost in future rates.

During 2001, contributions to the employee defined benefit pension plan increased from approximately $16 million in 2000 to approximately $43 million in 2001. This increase was necessitated by lower investment returns on assets in the employee benefit trusts and lower discount rates used to value the accumulated benefit obligations. It is anticipated that funding requirements for the plan will remain at the 2001 level or be somewhat higher for the next two to three years. As noted previously, the level of funding is somewhat dependent on returns on plan assets and discount rates. Higher returns on plan assets will decrease funding requirements and increases in discount rates will also reduce funding requirements to the plan. As discussed in Note 8 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 may be materially different than the requirements under the Company's prior pension plan.

During 2001, the Company made contributions to the pension plan that exceeded amounts previously recognized as net periodic pension expense and recorded a prepaid benefit obligation of approximately $21.3 million. At December 31, 2001, the Company's projected pension benefit obligation exceeded the fair value of pension plan assets by approximately $93.5 million. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87, "Employers' Accounting for Pensions", required the recognition of an additional minimum liability in the amount of approximately $83.1 million. The offset of this entry was an intangible asset and other comprehensive income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2001 and is a non-cash charge and 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 other comprehensive income. The amount in other comprehensive income represents a net periodic pension cost to be recognized in the Consolidated Statements of Income in future periods.

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, 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 will be adequate over the next three years to meet anticipated construction expenditures. Short-term borrowings will continue to be used to meet temporary cash requirements. OG&E has the necessary approvals to incur up to $400 million in short-term borrowings at any one time. Short-term borrowings will consist of some combination of bank borrowings and commercial paper. The Company's ability to access the commercial paper market could be adversely impacted by a commercial paper ratings downgrade. The line of credit contains ratings triggers that require annual fees and borrowing rates to increase if the Company suffers an adverse ratings impact. The impact of a downgrade would result in an increase in the cost of short-term borrowings of approximately five to 20 basis points, but would not result in any defaults or accelerations as a result of the ratings triggers. At December 31, 2001, the Company had in place a line of credit for up to $315 million, with $200 million expiring on January 15, 2002, $15 million expiring on June 6, 2002, and $100 million expiring on January 15, 2004. In January 2002, the Company's $200 million line of credit was renewed for $195 million, with an expiration date of January 9, 2003.

The Company continues to evaluate opportunities to enhance shareowner returns and achieve long-term financial objectives through acquisitions of assets that may complement its existing portfolio. Permanent financing could be required for such acquisitions if one was to occur.

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. The preparation of financial statements in conformity with generally accepted accounting principles requires management to use its judgment to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities. These assumptions and estimates could have a material affect on the Company's Consolidated Financial Statements. However, the

Company has taken conservative positions, where assumptions and estimates are used, in order to minimize the negative financial impact to the Company, which 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 energy trading contracts, pension plan assumptions, gas storage inventory, unbilled revenue for the electric utility, allowance for uncollectible accounts receivable and contingency reserves.

Energy trading contracts are entered into by OERI, the trading and marketing subsidiary of Enogex. All trading activities of OERI are accounted for on a mark-to-market basis. A risk committee charged with enforcing the trading policies, which include strict guidance on counterparties, procedures, credit and trading limits, monitors these activities. Trading activities include the trading and marketing of natural gas, electricity, crude oil and crude products. The vast majority of positions expire within two years, which is when the cash aspect of the transactions will be realized. In nearly all cases, independent market prices are obtained and compared to the values used for mark-to-market, and an oversight group outside of the trading and marketing organization monitors all modeling methodologies and assumptions. As a result of this mark-to-market valuation method, the value of the energy trading contracts may change significantly in the future as the market for the commodity changes, but the value is still subject to the risk loss limitations provided under the Company's trading policies.

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 and assumed discount rates. 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 affect on the amount of pension expense ultimately recognized. The pension plan rate assumptions are shown in Note 8 of the Consolidated Financial Statements. The assumed return on plan assets is based on management's expectation of the long-term return on plan assets portfolio.

The discount rate used to compute the present value of plan liabilities is based generally on rates of high grade corporate bonds with maturities similar to the average period over which benefits will be paid.

Gas storage inventory used in trading activities by Enogex is marked to market utilizing a gas index that in management's opinion approximates the current market value of natural gas in that region as of the balance sheet date. However, the actual market value could materially change in the future due to changes in market conditions such as weather or supply and demand.

OG&E reads its customers' meters and sends its bills 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. This unbilled revenue is estimated by adding the amount of electric power generated and

purchased less off-system sales and estimated line losses, which results in net kilowatt hours available for sale for the current period. From this number, the amount of billed kilowatt hours are deducted to arrive at an estimate of unbilled kilowatt hours for the period. These unbilled kilowatt hours are then multiplied by an estimate of the average price to be paid by customers to arrive at unbilled revenue. The estimates that management uses in this calculation could vary from the actual, but when consistently applied from period to period, this method should not result in any material differences.

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 that historical collection rates are not representative of future collections, there could be an affect on the amount of uncollectible expense recognized. As discussed in the results of operations, the level of electric accounts receivable charged off in 2001 increased due to various factors. As a result of this increase, the rate at which the allowance is being accrued has been increased.

From time to time, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to claims made by third parties 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 claim meets the definition of a contingent liability as set forth by generally accepted accounting principles, an estimate is made of the contingent liability and the appropriate accounting entries are reflected in the Company's financial statements.

Electric Competition; Regulation

As a result of the failure of California's attempt to deregulate electricity markets and more recently the impact of the Enron bankruptcy, attempts to restructure the electricity markets in Oklahoma and Arkansas have essentially been put on hold.

As previously reported, Oklahoma enacted in April 1997 the Electric Restructuring Act of 1997 (the "Act"), which was designed to provide for choice by retail customers of their electric supplier by July 1, 2002. Additional implementing legislation was to be adopted by the Oklahoma Legislature to address many specific issues associated with the Act and with deregulation. In May 2000, a bill addressing the specific issues of deregulation was passed in the Oklahoma State Senate and then was defeated in the Oklahoma House of Representatives. In May 2001, the Oklahoma Legislature passed Senate Bill 440 ("SB 440"), which postponed the scheduled start date for customer choice from July 1, 2002 until at least 2003. In addition to postponing the date for customer choice, the SB 440 calls for a nine-member task force to further study the issues surrounding deregulation. The task force includes the Governor or his designee, the Attorney General, the OCC Chair and several legislative leaders, among others. The Company will continue to participate actively in the legislative process and expects to remain a competitive supplier of electricity. The Company cannot predict what, if any, legislation will be adopted at the next legislative session.

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, like the Oklahoma law, will significantly affect OG&E's future operations. OG&E's electric service area includes parts of western Arkansas, including Fort Smith, the second-largest metropolitan market in the state. The Restructuring Law initially targeted customer choice of electricity providers by January 1, 2002. In February 2001, the law was amended to delay the start date of customer choice of electric providers in Arkansas until October 1, 2003, with the APSC having discretion to further delay implementation to October 1, 2005. The Restructuring Law also provides that utilities owning or controlling transmission assets must transfer control of such transmission assets to an independent system operator, independent transmission

company or regional transmission group, if any such organization has been approved by the FERC. Other provisions of the Restructuring Law permit municipal electric systems to opt in or out, permit recovery of stranded costs and transition costs and require filing of unbundled rates for generation, transmission, distribution and customer service. OG&E filed preliminary business separation plans with the APSC on August 8, 2000. The APSC has established a timetable to establish rules implementing the Arkansas restructuring statutes.

The OCC also has adopted rules that are designed to make the gas utility business in Oklahoma more competitive. These rules do not impact the electric industry. The rules are expected to offer increased opportunities to Enogex's pipeline and related businesses.

The efforts to increase competition in the electric industry at the retail level in Oklahoma and Arkansas have been paralleled and even surpassed by efforts 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 ("IPPs"). 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 trade. Moreover, power marketers are an increasingly important presence in the industry. 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, almost all of it from IPPs.

Notwithstanding these developments in the wholesale power market, 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, FERC only encouraged utilities to join and place their transmission systems under the operational control of independent system operators ("ISOs"). On December 20, 1999, FERC issued Order 2000, its final rule on regional transmission organizations ("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, 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.

OG&E is a member of the Southwest Power Pool ("SPP"), the regional reliability organization for Oklahoma, Arkansas, Kansas, Louisiana, Missouri and part of Texas. OG&E participated with the SPP in the development of regional transmission tariffs and executed an Agency Agreement with the SPP to facilitate interstate transmission operations within this region. In October 2000, the SPP filed its application with the FERC to become an RTO. In July 2001, the FERC determined that the SPP did not have adequate scope and configuration to be granted RTO status. The SPP was encouraged to explore the possibility of joining an RTO to be formed in the southeastern region of the United States and to explore the feasibility of becoming a part of the recently approved RTO being established by the Midwest Independent System Operator ("MISO"). The SPP and MISO entered negotiations during the

late summer of 2001 to combine the SPP and MISO and to form a new regional transmission entity that would combine the control areas of MISO and SPP, capture certain synergies that would be available from the combined organization, and allow member companies in the SPP certain options with respect to membership in the combined organization. The officers of MISO and of SPP, under the direction of their respective Boards of Directors have developed documentation to effect the merger of SPP and MISO into a new organization, and the transaction has been approved by the SPP Board of Directors and the required number of SPP member companies. OG&E intends to meet its obligations under Order 2000 and under the restructuring law in Arkansas first by executing a Conditional Withdrawal Agreement with the SPP. The Conditional Withdrawal Agreement will have the effect of terminating OG&E's membership in the SPP, except for regional reliability purposes, at such time as the MISO - SPP combination has received all necessary regulatory approvals and the transaction is closed. Following the closing of the transaction, OG&E currently anticipates that it will join MISO. The transfer of operational control of OG&E's transmission system to a FERC-approved RTO is not expected to significantly impact OG&E's financial results. Yet, it is expected to increase the markets in which OG&E can sell power at wholesale and, at the same time, to increase competition in such wholesale markets. As a low-cost producer of electricity with two of the most efficient power plants in the country, OG&E expects to remain a competitive supplier of electricity.

As discussed previously, legislation was enacted in Oklahoma and Arkansas that was to restructure the electric utility industry in those states. Although implementation of this restructuring legislation has been delayed, if and when implemented this legislation would deregulate OG&E's electric generation assets and discontinue the use of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" with respect to the related regulatory assets. 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 of up to $28 million, depending on the transition mechanisms developed by the legislature for the recovery of all or a portion of these net regulatory assets.

The enacted Oklahoma and Arkansas legislation would not affect OG&E's electric transmission and distribution assets and the Company believes that the continued use of SFAS No. 71 with respect to the related regulatory assets is appropriate. However, if utility regulators in Oklahoma and Arkansas were to adopt regulatory methodologies in the future that are not based on cost-of-service, the continued use of SFAS No. 71 with respect to the regulatory assets 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.

See Note 11 of Notes to Consolidated Financial Statements for a discussion of the following recent regulatory matters:

- On June 18, 2001, the OCC Staff (the “Staff”) approved a stipulation that OG&E previously entered into with the Staff, the Office of the Attorney General and a coalition of industrial customers regarding the competitive bid process.
- In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of OG&E.
- On January 28, 2002, OG&E, citing the need for investment in security and system reliability, filed a request for a $22 million annual rate increase.

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 senior risk management committee has been established to review these risks on a regular basis. The Company is exposed to market risk, including changes in certain commodity prices and interest rates.

To manage the volatility relating to these exposures, the Company enters into various derivative transactions pursuant to the Company's policies on hedging practices. Derivative 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 may utilize 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. The fair value of long-term debt is estimated based on quoted market prices and management's estimate of current rates available for similar issues. The following table itemizes the Company's long-term debt maturities and the weighted-average interest rates by maturity date. See "2001 Capital Requirements and Financing Activities" for related detailed discussion of the Company's interest rate swap agreements.

(dollars in millions)	2002	2003	2004	2005	2006	Thereafter	Total	2001 Year-end Fair Value
Fixed rate debt:								
Principal amount...	$ 115.0	$ 14.3	$ 53.0	$ 153.0	$ 2.0	$ 859.4	$1,196.7	$1,126.3
Weighted-average interest rate....	7.34%	7.70%	7.22%	7.09%	7.15%	7.48%	7.33%	---
Variable-rate debt:								
Principal amount...	---	---	---	---	---	$ 447.2	$ 447.2	$ 447.2
Weighted-average interest rate....	---	---	---	---	---	5.02%	5.02%	---

Commodity Price Exposure

The market risk inherent in the Company’s market risk sensitive instruments and positions are the potential loss in value arising from adverse changes in the Company’s commodity prices.

The prices of natural gas, natural gas liquids and electricity are subject to fluctuations resulting from changes in supply and demand. To partially reduce price risk caused by these market fluctuations, the Company may hedge (through the utilization of derivatives) a portion of the Company's supply and related purchase and sale contracts, as well as any anticipated transactions (purchases and sales). See "Price Risk Management Activities" in Note 1 of Notes to Consolidated Financial Statements. Because the commodities covered by these derivatives are substantially the same commodities that the Company buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

A sensitivity analysis has been prepared to estimate the price exposure to the market risk of the Company's natural gas, natural gas liquids and electricity commodity positions. The Company's daily net commodity position consists of natural gas inventories, purchased electric capacity, commodity purchase and sales contracts, and derivative financial and commodity instruments. The fair value of such position is a summation of the fair values calculated for each commodity by valuing each net position at quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in such prices over the next 12 months. The results of this analysis, which may differ from actual results, are as follows for fiscal 2001:

(dollars in thousands)	Trading	Non-Trading
Commodity market risk, net.....................	$ 380	$ ---

Contingencies

The Company through its subsidiaries is defending various claims and legal actions, including environmental actions, which are common to its operations. The Company's subsidiaries, primarily OG&E, also could be impacted by various proposed environmental regulations that if adopted, could result in significant increases in capital expenditures and operating expenses. For a further discussion of these matters, see Note 10 of Notes to Consolidated Financial Statements.

During the normal course of business, Enogex issues guarantees on behalf of OERI for the purpose of securing credit for trading activities. These guarantees are for prompt payment when due of amounts payable by OERI under various agreements. At December 31, 2001, accounts payable supported by guarantees was $28 million. Since these guarantees by Enogex represent security for prompt payment of payables obtained in the normal course of OERI's trading activities, the Company does not assume any additional liability as a result of this arrangement.

Besides the various existing contingencies herein described, and those described in Note 10 of Notes to Consolidated Financial Statements, the Company's ability to fund its future operational needs and to finance its construction program is dependent upon numerous other factors beyond its control, such as general economic conditions, abnormal weather, load growth, inflation, new environmental laws or regulations, and the cost and availability of external financing.

Item 8. Financial Statements and Supplementary Data.

CONSOLIDATED BALANCE SHEETS

December 31 *(dollars in thousands)*	**2001**	2000	1999
ASSETS			
CURRENT ASSETS:			
Cash and cash equivalents	**$ 32,493**	$ 454	$ 7,271
Accounts receivable - customers, less reserve of $8,863, $4,135 and $5,270, respectively	**205,155**	446,185	263,708
Accrued unbilled revenues	**35,600**	49,000	40,200
Accounts receivable - other	**16,958**	24,713	10,462
Fuel inventories	**77,209**	200,316	117,185
Materials and supplies, at average cost	**38,736**	41,517	39,194
Prepayments and other	**41,103**	45,715	12,328
Price risk management	**21,238**	45,727	4,583
Accumulated deferred tax assets	**10,035**	10,669	8,729
Total current assets	**478,527**	864,296	503,660
OTHER PROPERTY AND INVESTMENTS, at cost	**40,318**	36,980	31,012
PROPERTY, PLANT AND EQUIPMENT:			
In service	**5,507,240**	5,323,541	5,209,783
Construction work in progress	**47,812**	47,016	56,553
Total property, plant and equipment	**5,555,052**	5,370,557	5,266,336
Less accumulated depreciation	**2,291,304**	2,151,093	2,024,349
Net property, plant and equipment	**3,263,748**	3,219,464	3,241,987
DEFERRED CHARGES:			
Advance payments for gas	**8,500**	12,500	11,800
Income taxes recoverable through future rates	**37,615**	38,654	39,692
Intangible asset - unamortized prior service cost	**47,318**	---	---
Prepaid benefit obligation	**21,315**	---	---
Price risk management	**13,390**	5,668	---
Other	**85,861**	142,068	93,183
Total deferred charges	**213,999**	198,890	144,675
TOTAL ASSETS	**$ 3,996,592**	$ 4,319,630	$ 3,921,334

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

CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(dollars in thousands)*	**2001**	2000	1999
LIABILITIES AND STOCKHOLDERS' EQUITY			
CURRENT LIABILITIES:			
Short-term debt	**$ 115,000**	$ 284,500	$ 589,100
Accounts payable	**153,223**	330,445	161,183
Dividends payable	**25,909**	25,890	25,889
Customers' deposits	**28,423**	22,647	22,138
Accrued taxes	**28,835**	33,067	41,215
Accrued interest	**40,314**	40,699	28,191
Long-term debt due within one year	**115,000**	2,000	169,000
Provision for payments of take or pay gas	**30,800**	2,500	3,100
Fuel clause over recoveries	**23,358**	---	1,573
Price risk management	**7,925**	33,709	1,297
Other	**30,951**	34,475	34,175
Total current liabilities	**599,738**	809,932	1,076,861
LONG-TERM DEBT	**1,526,303**	1,648,523	1,140,532
DEFERRED CREDITS AND OTHER LIABILITIES:			
Accrued pension and benefit obligations	**100,086**	14,256	16,686
Accumulated deferred income taxes	**634,946**	618,360	566,137
Accumulated deferred investment tax credits	**52,279**	57,429	62,578
Price risk management	**3,759**	3,001	---
Other	**38,912**	103,821	39,161
Total deferred credits and other liabilities	**829,982**	796,867	684,562
STOCKHOLDERS' EQUITY:			
Common stockholders' equity	**444,689**	443,298	441,847
Retained earnings	**617,924**	621,010	577,532
Accumulated other comprehensive income (loss), net of tax	**(22,044)**	---	---
Total stockholders' equity	**1,040,569**	1,064,308	1,019,379
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 3,996,592**	$ 4,319,630	$ 3,921,334

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(dollars in thousands)*	**2001**	2000	1999
COMMON STOCK AND RETAINED EARNINGS:			
Common stock, par value $0.01 per share, authorized 125,000,000 shares; and outstanding 77,991,713, 77,921,997, and 77,863,370 shares, respectively	**$ 780**	$ 779	$ 779
Premium on capital stock	**443,909**	442,519	441,068
Retained earnings	**617,924**	621,010	577,532
Accumulated other comprehensive income (loss), net of tax	**(22,044)**	---	---
Total common stock and retained earnings	**1,040,569**	1,064,308	1,019,379
LONG-TERM DEBT:			
SERIES DATE DUE			
Senior Notes-			
6.250 % Senior Notes, Series Due October 15, 2000	**---**	---	110,000
7.125 % Senior Notes, Series Due October 15, 2005	**110,000**	110,000	---
6.500 % Senior Notes, Series Due July 15, 2017	**125,000**	125,000	125,000
Var. % Senior Notes, Series Due October 15, 2025	**107,588**	110,000	110,000
6.650 % Senior Notes, Series Due July 15, 2027	**125,000**	125,000	125,000
6.500 % Senior Notes, Series Due April 15, 2028	**100,000**	100,000	100,000
Other bonds-			
Var. % Garfield Industrial Authority, January 1, 2025	**47,000**	47,000	47,000
Var. % Muskogee Industrial Authority, January 1, 2025	**32,400**	32,400	32,400
Var. % Muskogee Industrial Authority, June 1, 2027	**56,000**	56,000	56,000
Unamortized premium and discount, net	**(2,609)**	(2,818)	(2,354)
Enogex Inc. notes (Note 6)	**577,674**	574,941	233,486
Transok Holding LLC (Note 6)	**163,250**	173,000	173,000
Trust Originated Preferred Securities (Note 5)	**200,000**	200,000	200,000
Total long-term debt	**1,641,303**	1,650,523	1,309,532
Less long-term debt due within one year	**115,000**	2,000	169,000
Total long-term debt (excluding long-term debt due within one year)	**1,526,303**	1,648,523	1,140,532
Total Capitalization	**$ 2,566,872**	$ 2,712,831	$ 2,159,911

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

CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(dollars in thousands except per share data)*	**2001**	2000	1999
OPERATING REVENUES	**$ 3,182,363**	$ 3,298,727	$ 2,172,434
COST OF GOODS SOLD	**2,266,143**	2,356,160	1,290,608
Gross margin on revenues	**916,220**	942,567	881,826
Other operation and maintenance	**391,606**	353,617	322,438
Depreciation and amortization	**181,224**	176,144	165,041
Taxes other than income	**65,375**	62,985	56,182
OPERATING INCOME	**278,015**	349,821	338,165
OTHER INCOME (EXPENSES), NET	**(2,026)**	2,595	480
EARNINGS BEFORE INTEREST AND TAXES	**275,989**	352,416	338,645
INTEREST INCOME (EXPENSES):			
Interest income	**4,401**	3,788	2,837
Interest on long-term debt	**(98,213)**	(101,452)	(60,727)
Interest on trust preferred securities	**(17,268)**	(17,268)	(3,358)
Other interest charges	**(11,755)**	(13,944)	(36,194)
Net interest income (expenses)	**(122,835)**	(128,876)	(97,442)
INCOME BEFORE TAXES	**153,154**	223,540	241,203
INCOME TAX EXPENSE	**52,583**	76,505	89,944
NET INCOME	**$ 100,571**	$ 147,035	$ 151,259
AVERAGE COMMON SHARES OUTSTANDING (thousands)	**77,929**	77,864	77,916
EARNINGS PER AVERAGE COMMON SHARE	**$ 1.29**	$ 1.89	$ 1.94
AVERAGE COMMON SHARES OUTSTANDING ASSUMING DILUTION (thousands)	**77,929**	77,864	77,916
EARNINGS PER AVERAGE COMMON SHARE ASSUMING DILUTION	**$ 1.29**	$ 1.89	$ 1.94
DIVIDENDS DECLARED PER SHARE	**$ 1.33**	$ 1.33	$ 1.33

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

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (dollars in thousands)	**2001**	2000	1999
BALANCE AT BEGINNING OF PERIOD	**$ 621,010**	$ 577,532	$ 529,768
ADD - net income	**100,571**	147,035	151,259
Total	**721,581**	724,567	681,027
DEDUCT:			
Cash dividends declared on common stock	**103,657**	103,557	103,495
Total	**103,657**	103,557	103,495
BALANCE AT END OF PERIOD	**$ 617,924**	$ 621,010	$ 577,532

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 (dollars in thousands)	**2001**	2000	1999
Net Income	**$ 100,571**	$ 147,035	$ 151,259
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment [($35,800) pretax]	**(21,945)**	---	---
Transition adjustment [($26,903) pretax]	**(16,492)**	---	---
Gain on qualifying cash flow hedge (total gain less ineffective portion) [$21,413 pretax]	**13,126**	---	---
Reclassification adjustments - transition adjustment [$26,903 pretax]	**16,492**	---	---
Reclassification adjustments - contract settlements [($21,413) pretax]	**(13,126)**	---	---
Deferred hedging losses [($161) pretax]	**(99)**	---	---
Total other comprehensive income (loss), net of tax	**(22,044)**	---	---
Total comprehensive income	**$ 78,527**	$ 147,035	$ 151,259

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (dollars in thousands)	**2001**	2000	1999
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	**$ 100,571**	$ 147,035	$ 151,259
Adjustments to Reconcile Net Income to Net Cash Provided from Operating Activities:			
Depreciation and amortization	**181,224**	176,144	165,041
Deferred income taxes and investment tax credits, net	**27,779**	46,999	31,093
Gain on sale of assets	**(385)**	(4,820)	---
Change in Certain Assets and Liabilities:			
Accounts receivable - customers	**241,030**	(182,477)	(69,875)
Accrued unbilled revenues	**13,400**	(8,800)	(17,700)
Fuel, materials and supplies inventories	**125,888**	(85,454)	(25,049)
Other current assets	**13,001**	(90,724)	16,274
Accounts payable	**(177,222)**	169,262	9,668
Accrued taxes	**(4,232)**	(8,148)	10,715
Accrued interest	**(385)**	12,508	7,110
Other current liabilities	**53,929**	31,048	(48,451)
Price risk management	**(7,595)**	(14,685)	---
Other operating activities	**(29,236)**	24,053	(5,832)
Net cash provided from operating activities	**537,767**	211,941	224,253
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	**(225,059)**	(179,471)	(181,163)
Proceeds from sale of assets	**1,431**	23,573	---
Acquisition of Transok	**---**	---	(531,767)
Other investing activities	**376**	637	2,832
Net cash used in investing activities	**(223,252)**	(155,261)	(710,098)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Retirement of long-term debt	**(11,750)**	(59,000)	(2,000)
Proceeds from long-term debt	**---**	400,000	---
Increase (decrease) in short-term debt, net	**(169,500)**	(304,600)	470,000
Issuance (retirement) of common stock	**1**	1	(30)
Premium on issuance (retirement) of common stock	**1,390**	1,450	(71,737)
Issuance of trust originated preferred securities	**---**	---	200,000
Contribution from minority interest owners	**1,449**	2,590	---

Obligation under capital lease	(409)	(381)	---
Cash dividends declared on common stock	(103,657)	(103,557)	(103,495)
Net cash provided from (used) in financing activities	(282,476)	(63,497)	492,738
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	32,039	(6,817)	6,893
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	454	7,271	378
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 32,493	$ 454	$ 7,271
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
CASH PAID DURING THE PERIOD FOR:			
Interest (net of amount capitalized of $708, $2,229 and $720, respectively)	$ 68,238	$ 105,288	$ 76,047
Income taxes	$ 42,991	$ 48,680	$ 52,428
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Interest rate swaps	$ (664)	$ ---	$ ---
Change in fair-value of long-term debt	$ 1,835	$ ---	$ ---
Other investing and financing activities	$ ---	$ 2,400	$ 3,182
Debt assumed in acquisition	$ ---	$ ---	$ 173,000
Current liabilities assumed in acquisition of Transok	$ ---	$ ---	$ 98,917

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

OGE Energy Corp. (collectively with its subsidiaries, the "Company") is an energy and energy services provider offering physical delivery and management of both electricity and natural gas in the south central United States. The Company conducts these activities through two business segments, the electric utility segment, which operations are conducted through Oklahoma Gas and Electric Company ("OG&E") and the energy supply segment, which operations are conducted primarily through Enogex Inc. ("Enogex"). All significant intercompany transactions have been eliminated in consolidation.

OG&E generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Enogex produces, gathers, processes, transports, markets and stores natural gas and produces, transports, and markets natural gas liquids in Oklahoma, Arkansas and west Texas. Enogex is also involved in commodity sales and services related to natural gas and electric power, primarily through its subsidiary, OGE Energy Resources Inc. ("OERI") and has investments in exploration and production of natural gas and oil with properties primarily in Michigan and Oklahoma.

The Company distributes 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 Federal Energy Regulatory Commission ("FERC") and adopted by the Oklahoma Corporation Commission ("OCC") and the Arkansas Public Service Commission ("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 costs that would otherwise be charged to expense can be deferred as regulatory assets, based on expected recovery from customers in future rates. Likewise, certain credits that would otherwise reduce expense are deferred as regulatory liabilities based on 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. At December 31, 2001, regulatory assets and regulatory liabilities are being amortized and reflected in rates charged to customers over periods up to 20 years.

The components of other deferred charges and credits, and regulatory assets and liabilities on the Consolidated Balance Sheets included the following, as of December 31:

Other Deferred Charges and Credits

(dollars in thousands)	**2001**	2000	1999
OG&E Deferred Charges:			
Insurance claims for generating stations	$ 2,265	$ 420	$ 4,654
Unamortized debt expense	5,203	5,565	5,196
Unamortized loss on reacquired debt	24,473	25,644	27,281
Miscellaneous	4,337	4,471	4,116
Total electric utility deferred charges	36,278	36,100	41,247
Enogex and Other Operations Deferred Charges:			
Enogex gas sales contracts	7,246	8,832	10,891

Enogex pipeline over-deliveries	**18,010**	68,510	14,263
Unamortized debt expense	**12,248**	13,141	10,008
Enogex minority interest asset	**4,342**	4,838	6,845
Enogex pipeline liquid line fill	**4,513**	4,513	3,610
Miscellaneous	**3,224**	6,134	6,319
Total non-electric utility deferred charges	**49,583**	105,968	51,936
Total Other Deferred Charges	**$ 85,861**	$ 142,068	$ 93,183
OG&E Deferred Credits:			
Take or pay gas litigation	**$ 8,500**	$ 12,500	$ 11,800
Miscellaneous	**500**	---	133
Total electric utility deferred credits	**9,000**	12,500	11,933
Enogex and Other Operations Deferred Credits:			
Enogex pipeline under-deliveries	**6,260**	68,182	5,072
Enogex obligations under capital lease, non-current	**8,910**	9,319	9,699
Enogex minority interest liability	**10,078**	8,836	8,234
Miscellaneous	**4,664**	7,985	4,223
Total non-electric utility deferred credits	**29,912**	94,322	27,228
Total Other Deferred Credits	**$ 38,912**	$ 106,822	$ 39,161

Regulatory Assets and Liabilities

(dollars in thousands)	**2001**	2000	1999
Regulatory Assets:			
Income taxes recoverable from customers	**$ 73,345**	$ 83,617	$ 93,888
Unamortized loss on reacquired debt	**24,473**	25,644	27,281
Miscellaneous	**432**	461	392
Total Regulatory Assets	**98,250**	109,722	121,561
Regulatory Liabilities:			
Income taxes refundable to customers	**(35,730)**	(44,963)	(54,196)
Net Regulatory Assets	**$ 62,520**	$ 64,759	$ 67,365

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.

Accounting Pronouncements

Effective January 1, 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB 133" and SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities". SFAS No. 133 requires the Company to record all derivatives on the balance sheet at fair value. Changes in the fair value of derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, must be recognized as a derivative fair value gain or loss in the income statement. Changes in fair value of effective fair value hedges are recorded in price risk management in the accompanying Consolidated Balance Sheets, with a corresponding net change in the hedged asset or liability. Changes in fair value of effective cash flow hedges are recorded as a component of Accumulated Other Comprehensive Income, which is later reclassified to earnings when the hedged transaction occurs. Physical delivery contracts, which are deemed to be normal purchases or normal sales, are not accounted for as derivatives.

The Company accounted for adoption of SFAS No. 133 on January 1, 2001, by recording a cumulative effect transition adjustment debit to Accumulated Other Comprehensive Income of approximately $26.9 million ($16.5 million net of tax). This unrealized loss was related to the derivative fair value of qualifying cash flow hedges as of the date of adoption and was reclassified to earnings as the related hedged transactions occurred. As of December 31, 2001, this amount had been reclassified to earnings. However, the initial unrealized loss was offset by subsequent gain on these qualifying cash flow hedges of approximately $21.4 million ($13.1 million net of tax). The Company also recorded a gain, included in Operating Revenues, related to the ineffective portion of hedge derivatives, for production hedges, of $4.7 million ($3.0 million net of tax) for 2001, resulting in a loss of only approximately $0.8 million ($0.4 million net of tax).

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations". SFAS No. 143 will affect the Company's accrued plant removal costs for generation, transmission, distribution, processing and oil and gas production facilities and will require 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 fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement is incurred, the liability shall be recognized when a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Adoption of SFAS No. 143 is required for financial statements for periods beginning after June 15, 2002. The Company will adopt this new standard effective January 1, 2003. Management has not yet determined what the impact of this new standard will be on its consolidated financial position or results of operation.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". SFAS No. 144 requires that an impairment loss be recognized only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and that the measurement of any impairment loss be the difference between the carrying amount and fair value of the asset. Adoption of SFAS No. 144 is required for financial statements for periods beginning after December 15, 2001. The Company adopted this new standard effective January 1, 2002, and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operation.

Price Risk Management Activities

Enogex, in the normal course of business, enters into fixed price contracts for either the purchase or sale of natural gas and electricity at future dates. Due to fluctuations in the natural gas and electricity markets, Enogex buys or sells natural gas and electricity futures contracts, swaps or options to hedge the price and basis risk associated with the specifically identified purchase or sales contracts as well as future production from its development and production properties. Prior to January 1, 2001, Enogex accounted for changes in the market value of qualifying hedging instruments as deferred gains or losses until the production month of the hedged transaction, at which time the gain or loss was recognized in the results of operations. Subsequent to January 1, 2001, the Company accounts for changes in the market value of qualifying hedging instruments in accordance with SFAS No. 133. The specific accounting treatment for changes in the market value of the derivative instrument is determined based on the designation of the derivative instrument as a cash flow, fair value or foreign currency exposure hedge, and the effectiveness of the derivative instrument. Additionally, Enogex may use derivative contracts as an enhancement or speculative trade, subject to the Company's policies on risk management. Enogex recognizes the gain or loss on enhancement or speculative contracts as market values change in the results of operations. The Company adheres to FASB Emerging Issues Task Force Issue ("EITF") No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities", under which all of Enogex's energy trading contracts are marked to market with the corresponding market gains or losses recognized in the results of operations.

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 liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Property, Plant and Equipment

All property, plant and equipment are recorded at cost. Electric utility plant is recorded at its original cost. Newly constructed plant is added to plant balances at costs which include contracted services, direct labor, materials, overhead and allowance for funds used during construction. Replacements of major units of property are capitalized as plant. The replaced plant is removed from plant balances and the cost of such property together with the cost of removal 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.

Depreciation

The provision for depreciation, which was approximately 3.1 percent of the average depreciable utility plant for 2001 and 2000, and 3.2 percent for 1999, is provided on a straight-line method over the estimated service life of the property. 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's gas pipeline, gathering systems, compressors and gas processing plants are depreciated on a straight-line method over periods ranging from 17 to 83 years. Development and production properties are depreciated using the units-of-production method.

Allowance For Funds Used During Construction

Allowance for funds used during construction ("AFUDC") is calculated according to FERC pronouncements for the imputed cost of equity and borrowed funds. AFUDC, a non-cash item, is reflected as a credit on the Consolidated Statements of Income and a charge to construction work in progress.

AFUDC rates, compounded semi-annually, were 4.87, 6.68 and 5.36 percent for the years 2001, 2000 and 1999, respectively.

Fair Value of Financial Instruments

The carrying value of the financial instruments on the Consolidated Balance Sheets not otherwise discussed in these notes approximates fair value.

Cash and Cash Equivalents

For purposes of these 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 market.

The Company's cash management program utilizes controlled disbursement banking arrangements. Outstanding checks in excess of cash balances totaled $28.9 million, $28.5 million and $11.7 million at December 31, 2001, 2000 and 1999, respectively, and are classified as accounts payable in the accompanying Consolidated Balance Sheets. Sufficient funds were available to fund these outstanding checks when they were presented for payment.

Heat Pump Loans

OG&E has a heat pump loan program, whereby, qualifying customers may obtain a loan from OG&E to purchase a heat pump. Customer loans are available from a minimum of $1,500 to a maximum of $13,000 with a term of 6 months to 72 months. The finance rate is based upon short-term loan rates and is reviewed and updated periodically. The interest rates were 10.99 at December 31, 2001 and 2000, and 8.99 percent at December 31, 1999.

The current portion of these loans totaled $1.9 million, $1.5 million and $0.6 million at December 31, 2001, 2000 and 1999, respectively, and are classified as accounts receivable - customers in the accompanying Consolidated Balance Sheets. The noncurrent portion of these loans totaled $7.5 million, $5.9 million and $2.3 million at December 31, 2001, 2000 and 1999, respectively, and are classified as other property and investments in the accompanying Consolidated Balance Sheets. OG&E sold approximately $12.7 million of its heat pump loans in 1999.

Revenue Recognition

OG&E customers are billed monthly on a cycle basis. OG&E accrues estimated revenues for services provided but not yet billed, as the cost of providing service is recognized as incurred. Enogex accrues revenues as the products and services are delivered. Substantially all of Enogex's natural gas and power marketing operations are accounted for under a mark-to-market accounting methodology. Under mark-to-market 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 gains or losses recognized in earnings and offsetting amounts recorded as assets and liabilities which are included in price risk management activities in the accompanying Consolidated Balance Sheets.

Automatic Fuel Adjustment Clauses

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to that component in cost-of-service for ratemaking, are charged to substantially all of OG&E's electric customers through automatic fuel adjustment clauses, which are subject to periodic review by the OCC, the APSC and the FERC. In June 2001, the OCC approved the Gas Transportation Adjustment Rider ("GTAC Rider") for $2.7 million annually. The GTAC Rider is a credit for gas transportation cost recovery. In March 2000, the OCC approved the Acquisition Premium Credit Rider ("APC Rider") for $10.7 million annually. The purpose of this rider is to credit the Oklahoma retail customers for the completion of the OCC authorized recovery of the premium paid by OG&E when it acquired Enogex in 1986. The GTAC Rider and the APC Rider are both applicable to each Oklahoma retail rate schedule to which OG&E's fuel cost adjustment clause applies.

Fuel Inventories

Fuel inventories for the generation of electricity consists 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 $13.0 million and $11.6 million for 2001 and 2000, respectively, and lower than the stated LIFO cost by approximately $0.9 million for 1999, based on the average cost of fuel purchased late in the respective years. Natural gas products inventories used in Enogex's energy trading activities and accounted for under EITF No. 98-10 are valued at market and amount to $22.3 million, $124.8 million and $41.7 million of the fuel inventory for 2001, 2000 and 1999, respectively.

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. The accrued vacation totaled $16.9 million at December 31, 2001 and $14.4 million at December 31, 2000 and 1999, and is classified as other current liabilities in the accompanying Consolidated Balance Sheets.

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 amounts have been reclassified on the consolidated financial statements to conform to the 2001 presentation.

2. INCOME TAXES

The items comprising income tax expense are as follows:

Year ended December 31 *(dollars in thousands)*	**2001**	2000	1999
Provision For Current Income Taxes:			
Federal	**$ 23,882**	$ 23,311	$ 50,090
State	**2,790**	6,824	8,617
Total Provision For Current Income Taxes	**26,672**	30,135	58,707
Provisions (Benefit) For Deferred Income Taxes, net:			
Federal			
Depreciation	**20,261**	51,398	29,392
Repair allowance	**109**	1,711	1,978
Removal costs	**3,387**	2,710	3,461
Salvage	**(1,623)**	(1,718)	(3,131)
Software development costs	**---**	(3,162)	2,906
Casualty losses	**3,507**	(5,439)	5,167
Contributions in aid of construction	**(4,760)**	(2,689)	(1,249)
Company restructuring	**24**	46	100
Pension expense	**5,587**	1,325	(2,626)
Bond redemption-unamortized costs	**(353)**	(1,064)	249
Partnerships	**1,559**	4,682	4,270
Other	**179**	(2,685)	(6,134)
State	**5,053**	7,032	1,858
Total Provision For Deferred Income Taxes, net	**32,930**	52,147	36,241

	2001	2000	1999
Deferred Investment Tax Credits, net	**(7,010)**	(5,150)	(5,150)
Income Taxes Relating to Other Income and Deductions	**(9)**	(627)	146
Total Income Tax Expense	**$ 52,583**	$ 76,505	$ 89,944
Pretax Income	**$ 153,154**	$ 223,540	$ 241,203

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

Year ended December 31	2001	2000	1999
Statutory federal tax rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	**3.3**	4.0	2.8
Tax credits, net	**(6.2)**	(3.4)	(3.4)
Other, net	**2.2**	(1.4)	2.9
Effective income tax rate as reported	**34.3%**	34.2%	37.3%

The Company files consolidated income tax returns. Income taxes are allocated to each company based on its separate taxable income or loss.

Investment tax credits on electric utility property have been deferred and are being amortized to income over the life of the related property.

The Company 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 Income Taxes are as follows:

(dollars in thousands)	2001	2000	1999
Current Accumulated Deferred Tax Assets:			
Accrued vacation	**$ 5,846**	$ 5,184	$ 5,497
Uncollectible accounts	**2,983**	4,089	1,776
Capitalization of indirect costs	**258**	318	249
RAR interest	**774**	774	774
Provision for Worker's Compensation claims	**265**	272	348
Other	**(91)**	32	85
Current Accumulated Deferred Tax Assets	**$ 10,035**	$ 10,669	$ 8,729
Non-Current Accumulated Deferred Tax Liabilities:			
Accelerated depreciation and other property-related differences	**$ 609,573**	$ 587,038	$ 532,814
Allowance for funds used during construction	**37,466**	34,093	37,152
Income taxes recoverable through future rates	**28,389**	32,365	36,335
Bond redemption-unamortized costs	**8,549**	8,964	9,640
Total Non-Current Accumulated Deferred Tax Liabilities	**683,977**	662,460	615,941
Non-Current Accumulated Deferred Tax Assets:			
Deferred investment tax credits	**(15,592)**	(18,388)	(20,130)
Income taxes refundable through future rates	**(13,830)**	(17,404)	(20,974)
Postemployment medical and life insurance benefits	**(2,952)**	(1,792)	(1,795)
Company pension plan	**(10,602)**	(4,078)	(5,206)
Other	**(6,055)**	(2,438)	(1,699)
Total Non-Current Accumulated Deferred Tax Assets	**(49,031)**	(44,100)	(49,804)
Non-Current Accumulated Deferred Income Tax Liabilities	**$ 634,946**	$ 618,360	$ 566,137

3. COMMON STOCK AND RETAILED EARNINGS

On January 15, 1999, the Company repurchased three million shares of its Common Stock under an Advanced Share Repurchase agreement with CIBC Oppenheimer Corp. The purchase price was $80.4 million or $26.8125 per share, the closing price on January 15, 1999. Under the terms of this Advanced Share Repurchase Agreement, the Company agreed to bear the risk of increases and the benefit of decreases on the price on the Common Stock until CIBC Oppenheimer Corp. replaced, through open market purchases or privately negotiated transactions, the shares sold to the Company. Also, there were 67,410, 58,627 and 65,831 shares of new stock issued pursuant to the Stock Incentive Plan during 2001, 2000 and 1999, respectively. In 2001, there were also 2,306 shares of new stock issued due to exercised stock options. The $1.4 million and $1.5 million increase in 2001 and 2000, respectively, in premium on capital stock as presented on the Consolidated Statements of Capitalization, represents the issuance of common stock pursuant to the Stock Incentive Plan.

There were 2,709,564 shares of unissued common stock reserved for the various employee and Company stock plans at December 31, 2001. With the exception of the Stock Incentive Plan, the common stock requirements, pursuant to those plans, are currently being satisfied with common stock purchased on the open market.

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 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.

4. STOCK INCENTIVE PLAN

On January 21, 1998, the Company adopted a Stock Incentive 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 has authorized the issuance of up to 4,000,000 shares under the plan.

Restricted Stock

The Company distributed 67,410, 58,627 and 65,831 shares of restricted common stock under the Stock Incentive Plan during 2001, 2000 and 1999, respectively. The restricted stock distributed vests at the end of three years. Each share of restricted stock is subject to a restriction period of three years during which the share 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.

Stock Options

Options granted under the Stock Incentive Plan vest in one-third annual installments beginning one year from the date of grant and have a contractual life of 10 years. Stock option transactions related to the Company's Stock Incentive Plan are summarized in the following table:

	2001		2000		1999	
	Number of Options	**Weighted Average Price**	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Options Outstanding at beginning of year..	**1,190,200**	**$24.7186**	870,400	$27.2361	427,600	$25.7500
Granted..................................	**428,100**	**22.5000**	364,200	18.2500	442,800	28.7500
Exercised................................	**(2,306)**	**18.2500**	---	---	---	---
Cancelled................................	**(45,967)**	**25.0179**	(44,400)	24.1622	---	---
Options Outstanding at end of year..........	**1,570,027**	**$24.0729**	1,190,200	$24.7186	870,400	$27.2361
Options Exercisable at end of year..........	**772,260**	**$25.7166**	407,666	$26.6522	142,533	$25.7500

During 1996, the Company adopted SFAS No. 123 and pursuant to its provision elected to continue using the intrinsic value method of accounting for stock-based awards granted to employees in accordance with Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees". Accordingly, the Company has not recognized compensation expense for its stock-based awards to employees. Using the Black-Scholes pricing model, the estimated fair value of each option granted was $3.61 in 2001.

The following table shows assumptions used to estimate the fair value of options granted in 2001:

Expected life of options...........................	7 years
Risk-free interest rate............................	5.17%
Expected volatility................................	24.03%
Expected dividend yield............................	5.70%

Changes in common stock outstanding were:

(shares in thousands)	**2001**	2000	1999
Shares outstanding January 1.............................	**77,922**	77,863	80,798
Repurchased shares.......................................	**---**	---	(3,000)
Issued/reacquired under the Stock Incentive Plan, net.....	**68**	59	65
Exercised stock options..................................	**2**	---	---
Shares outstanding December 31............................	**77,992**	77,922	77,863

The following table reflects pro forma earnings available for common stock had the Company elected to adopt the fair value approach to SFAS No. 123:

(dollars in thousands)		**2001**	2000	1999
Earnings available for common stock:	As Reported................	**$100,571**	$147,035	$151,259
	Pro Forma..................	**99,736**	146,438	150,864

In 2001, reported earnings per share were $1.29. Had the Company elected to adopt the fair value approach to SFAS 123, earnings per share would have been $1.28. In 2000, reported earnings per share were $1.89, while the pro forma earnings per share were $1.88. Reported and pro forma earnings per share amounts were equivalent for 1999.

5. TRUST PREFERRED SECURITIES OF SUBSIDIARY

On October 21, 1999, the OGE Energy Capital Trust I, a wholly owned financing trust of the Company, issued $200 million principal amount of 8.375 percent trust preferred securities that mature in 2039. The proceeds of this debt were used to repay a portion of outstanding short-term borrowings under the revolving credit agreement implemented in connection with the Tejas Transok Holding, L.L.C. and subsidiaries ("Transok") acquisition. Distributions paid by the financing trust on the preferred securities are financed through payments on debt securities issued by the Company and held by the financing trust, which are eliminated in the Company's consolidation. The preferred securities are redeemable at $25 per share beginning in 2004. Distributions and redemption payments are guaranteed by the Company. Distributions paid to preferred security holders are recorded as interest expense in the Consolidated Statements of Income.

6. LONG-TERM DEBT

On January 10, 2001, Enogex retired $5 million principal amount of 7.75 percent medium-term notes due April 24, 2023. On August 8, 2001, Enogex retired $4.75 million principal amount of 7.00 percent medium-term notes due December 1, 2004. This debt was assumed as part of the Transok acquisition.

During March 2001, the Company entered into two separate interest rate swap agreements; (i) OG&E entered into an interest rate swap agreement to convert $110 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) effective July 15, 2001, Enogex entered into an interest rate swap agreement to convert $200 million of 8.125 percent fixed rate debt due, January 15, 2010, to a variable rate based on LIBOR. The objective of these interest rate swaps was to hedge the fair value of the underlying debt and to raise the percentage of total corporate floating rate debt more in line with industry standard and to achieve a lower cost of debt. These interest rate swaps qualified as fair value hedges under SFAS No. 133 and meet all requirements for a determination that there was no ineffective portion as allowed under the shortcut method under SFAS No. 133. At December 31, 2001, the net change in fair values pursuant to the interest rate swaps is approximately $1.8 million and is included in non-current price risk management in the accompanying Consolidated Balance Sheets. A corresponding net increase of $1.8 million is reflected in the Company's long-term debt at December 31, 2001, as neither fair value hedge has ineffectiveness as of December 31, 2001.

On October 15, 2000, a $110 million series of OG&E's 6.25 percent Senior Notes matured. The Company temporarily funded this debt through short-term borrowings. On October 23, 2000, OG&E issued $110 million of 7.125 percent Senior Notes, Series due October 15, 2005. Net proceeds from this transaction were used to repay the temporary short-term borrowings from the Company.

Enogex retired $57 million of long-term debt that matured in the third quarter of 2000. This debt consisted of $23 million principal amount of 6.77 percent medium-term notes due August 7, 2000, $4 million principal amount of 6.76 percent medium-term notes due August 7, 2000, $20 million principal amount of 6.68 percent medium-term notes due August 31, 2000 and $10 million principal amount of 6.70 percent medium-term notes due September 1, 2000.

On July 1, 1999, Enogex completed its acquisition of Transok for approximately $710.3 million, which included assumption of $173 million of long-term debt. To repay the remaining balance of the temporary short-term debt associated with the Transok acquisition, Enogex, on January 14, 2000, sold $400 million of unsecured 8.125 percent Senior Notes due January 15, 2010. During 2000, Enogex entered into a series of one year interest rate swap agreements to manage interest costs associated with this $400 million issue. The effect of these swap agreements reduced the overall effective interest rate from 8.125 percent to 6.6875 percent during 2000. The interest rate swaps expired in January 2001. The balance of the proceeds from this new debt was used for general corporate purposes. The following table itemizes the Enogex long-term debt assumed as part of the Transok acquisition:

(dollars in thousands)	**2001**	2000	1999
Series Due 2002 -- 7.32% - 8.13%..................	**$ 50,000**	$ 50,000	$ 50,000
Series Due 2003 -- 6.60% - 8.28%..................	**12,300**	12,300	12,300
Series Due 2004 -- 6.71% - 8.34%..................	**21,000**	25,750	25,750
Series Due 2005 -- 6.81% - 7.71%..................	**40,950**	40,950	40,950
Series Due 2007 -- 8.28%..........................	**3,000**	3,000	3,000
Series Due 2008 -- 7.07%..........................	**1,000**	1,000	1,000
Series Due 2012 -- 8.35% - 8.90%..................	**10,000**	10,000	10,000
Series Due 2017 -- 8.96%..........................	**15,000**	15,000	15,000
Series Due 2023 -- 7.75%..........................	**10,000**	15,000	15,000
Total..	**$ 163,250**	$ 173,000	$ 173,000

The following table itemizes the other Enogex long-term debt:

December 31 *(dollars in thousands)*	**2001**	2000	1999
Series Due August 7, 2000 -- 6.76% - 6.77%........	**$ ---**	$ ---	$ 27,000
Series Due August 31, 2000 -- 6.68%..............	**---**	---	20,000
Series Due September 1, 2000 - 6.70%.............	**---**	---	10,000
Series Due August 7, 2002 -- 7.02% - 7.05%........	**63,000**	63,000	63,000
Series Due July 23, 2004 -- 6.79%................	**30,000**	30,000	30,000
Series Due January 15, 2010 - 8.125%.............	**200,000**	400,000	---
Series Due January 15, 2010 - Var. %.............	**204,247**	---	---
Series Due June 1, 2018 -- 7.15%.................	**73,000**	75,000	77,000
Series Due July 1, 2020 -- 7.00%.................	**7,427**	6,941	6,486
Total..	**$ 577,674**	$ 574,941	$ 233,486

The $73 million principal amount of 7.15 percent Senior Notes due June 1, 2018, shown above, are subject to semiannual principal payments of $1 million each.

Maturities of the Company's long-term debt during the next five years consist of $115 million in 2002; $14.3 million in 2003; $53 million in 2004, and $153 million in 2005 and $2 million in 2006.

The Company has previously incurred costs related to debt refinancings. Unamortized debt expense and unamortized loss on reacquired debt, and unamortized premium and discount on long-term debt are being amortized over the life of the respective debt and are classified as deferred charges - other and long-term debt, respectively, in the accompanying Consolidated Balance Sheets.

7. SHORT-TERM DEBT

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by obtaining short-term bank loans. The maximum and average amounts of short-term borrowings during 2001 were $298.9 million and $174.9 million, respectively, at a weighted average interest rate of 4.87%. The weighted average interest rates for 2000 and 1999 were 6.68% and 5.36%, respectively. Short-term debt in the amount of $115 million was outstanding at December 31, 2001. OG&E has the necessary approvals to incur up to $400 million in short-term borrowings at any one time. The Company's ability to access the commercial paper market could be adversely impacted by a commercial paper ratings downgrade. The line of credit contains ratings triggers that require annual fees and borrowing rates to increase if the Company suffers an adverse ratings impact. The impact of a downgrade would result in an increase in the cost of short-term borrowings of approximately five to 20 basis points, but would not result in any defaults or accelerations as a result of the ratings triggers. At December 31, 2001, the Company had in place a line of credit for up to $315 million, $200 million expiring on January 15, 2002, $15 million expiring on June 6, 2002, and $100 million expiring on January 15, 2004. In January 2002, the Company's line of credit for $200 million was renewed for $195 million, with an expiration date of January 9, 2003.

On April 6, 2001, the Company entered into a one-year interest rate swap agreement to lock in a fixed rate of 4.41 percent, effective April 10, 2001, on $140 million of variable rate short-term debt. This

interest rate swap initially qualified for hedge accounting treatment as a cash flow hedge under SFAS No. 133. However, due to unexpected changes in the level of commercial paper issued during the third quarter, hedge accounting treatment under SFAS No. 133 was discontinued as of July 1, 2001, and all subsequent changes in the market value of the swap are being recorded as interest expense. The objective of this interest rate swap was to reduce exposure to short-term interest rate volatility associated with the Company's commercial paper program.

8. PENSION AND POSTRETIREMENT BENEFIT PLANS

All eligible employees of the Company are covered by a non-contributory defined benefit pension plan. In early 2000, the Board 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 ten years prior to 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) for an employee retiring prior to age 62, 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, 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 to comply with the minimum required contributions under existing tax regulations. Additional amounts may be contributed from time to time to increase the funded status of the Plan. The Company made contributions of $43 million during 2001 to increase the Plan's 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 2001, the Company made contributions to the pension plan that exceeded amounts previously recognized as net periodic pension expense and recorded a prepaid benefit obligation of approximately $21.3 million. At December 31, 2001, the Company's projected pension benefit obligation exceeded the fair value of pension plan assets by approximately $93.5 million. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87, "Employers' Accounting for Pensions", required the recognition of an additional minimum liability in the amount of approximately $83.1 million. The offset of this entry was an intangible asset and other comprehensive income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2001 and is a non-cash charge and 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 other comprehensive income. The amount in 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 U.S. Government securities, listed common stock and corporate debt.

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for retired members ("postretirement benefits"). Under the existing plan, employees retiring from the Company on or after attaining age 55 who have met certain length of service requirements were entitled to these benefits. Pursuant to amendments made to the medical plan in 2000, 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 benefits. Employees hired after January 31, 2000, are not entitled to the medical benefits but are entitled to the life insurance 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 cost-of-service in future ratemaking proceedings.

A reconciliation of the funded status of the plans and the amounts included in the Company's Consolidated Balance Sheets follows:

Projected Benefit Obligations:

	Pension Plan			Postretirement Benefit Plans		
(dollars in thousands)	**2001**	2000	1999	**2001**	2000	1999
Beginning obligations......	**$(395,235)**	$(299,996)	$(342,433)	**$(102,387)**	$ (83,428)	$ (89,094)
Service cost..............	**(12,048)**	(10,559)	(8,241)	**(2,046)**	(2,084)	(2,695)
Interest cost.............	**(29,941)**	(27,516)	(21,363)	**(8,313)**	(7,200)	(6,003)
Participant contributions..	**---**	---	---	**(1,236)**	(1,093)	(1,143)
Plan changes...............	**---**	(20,528)	---	**---**	(17,373)	(1,500)
Actuarial gains (losses)...	**(5,908)**	(77,862)	53,535	**(17,116)**	(379)	7,950
Benefits paid.............	**39,540**	40,460	17,695	**10,312**	9,170	9,057
Expenses..................	**1,368**	766	811	**---**	---	---
Ending obligations.........	**$(402,224)**	$(395,235)	$(299,996)	**$(120,786)**	$(102,387)	$ (83,428)

Fair Value of Plans' Assets:

	Pension Plan			Postretirement Benefit Plans		
(dollars in thousands)	**2001**	2000	1999	**2001**	2000	1999
Beginning fair value...........	**$ 296,500**	$ 311,937	$ 304,169	**$ 55,551**	$ 55,509	$ 52,264
Actual return on plans' assets..	**10,119**	9,597	22,517	**(2,738)**	42	3,245
Employer contributions..........	**43,016**	16,190	3,757	**9,076**	6,184	6,307
Participants' contributions.....	**---**	---	---	**1,236**	943	980
Benefits paid..................	**(39,540)**	(40,460)	(17,695)	**(10,312)**	(7,127)	(7,287)
Expenses........................	**(1,368)**	(764)	(811)	**---**	---	---
Other...........................	**---**	---	---	**---**	---	---
Ending fair value..............	**$ 308,727**	$ 296,500	$ 311,937	**$ 52,813**	$ 55,551	$ 55,509

Net Periodic Benefit Cost:

	Pension Plan			Postretirement Benefit Plans		
(dollars in thousands)	**2001**	2000	1999	**2001**	2000	1999
Service cost....................	**$ 12,048**	$ 10,559	$ 8,241	**$ 2,046**	$ 2,084	$ 2,695
Interest cost...................	**29,941**	27,516	21,363	**8,313**	7,200	6,003
Return on plan assets...........	**(21,300)**	(24,160)	(27,374)	**(5,356)**	(4,985)	(3,963)
Amortization of transition obligation..................	**(1,264)**	(1,263)	(1,263)	**2,749**	2,749	2,749
Amortization of net (gain) loss.	**978**	(91)	---	**(890)**	(1,727)	(1,244)
Net amount capitalized or deferred.....................	**(3,419)**	(2,245)	(880)	**---**	---	(1,087)
Net amortization and deferral...	**---**	---	(29)	**---**	---	---
Amortization of unrecognized prior service cost...........	**5,351**	4,619	3,159	**2,050**	1,436	104
Net periodic benefit costs......	**$ 22,335**	$ 14,935	$ 3,217	**$ 8,912**	$ 6,757	$ 5,257

Funded Status of Plans:

	Pension Plan			Postretirement Benefit Plans		
(dollars in thousands)	**2001**	2000	1999	**2001**	2000	1999
Funded status of the plans......	**$ (93,497)**	$ (98,735)	$ 11,941	**$ (67,973)**	$ (46,836)	$ (27,919)
Unrecognized net (gain) loss....	**66,965**	47,435	(47,326)	**8,662**	(17,428)	(24,337)
Unrecognized prior service cost..........................	**47,847**	53,197	37,289	**15,282**	17,333	1,396
Unrecognized transition obligation....................	**---**	(1,265)	(2,527)	**30,240**	32,988	35,738
Net amount recognized..........	**$ 21,315**	$ 632	$ (623)	**$ (13,789)**	$ (13,943)	$ (15,122)

Amounts recognized in the Consolidated Balance Sheets consist of:

	Pension Plan		
(dollars in thousands)	**2001**	2000	1999

Prepaid benefit cost	$ 21,315	N/A	N/A
Accrued benefit liability	(83,118)	N/A	N/A
Intangible asset	47,318	N/A	N/A
Deferred tax asset	13,855	N/A	N/A
Accumulated other comprehensive income	21,945	N/A	N/A
Net amount recognized	$ 21,315	N/A	N/A

N/A - not applicable

Rate Assumptions:

	Pension Plan			Postretirement Benefit Plans		
	2001	2000	1999	**2001**	2000	1999
Discount rate	**7.25%**	8.00%	8.00%	**7.25%**	8.00%	8.00%
Rate of return on plans' assets	**9.00%**	9.00%	9.00%	**9.00%**	9.00%	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	**6.00%**	6.50%	7.00%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2006**	2006	2006

N/A - not applicable

Assumed health care cost trend rates have a significant effect on the amounts reported for the postretirement medical benefit plans.

The effects of a one-percentage point increase on the aggregate of the service and interest components of the net periodic postretirement health care benefits would be approximately $1.2 million, $1.1 million and $1.0 million at December 31, 2001, 2000 and 1999, respectively. The effects of a one-percentage point decrease on the aggregate of the service and interest components of the net periodic postretirement health care benefits would be decreases of approximately $1.0 million, $0.9 million and $0.9 million at December 31, 2001, 2000 and 1999, respectively.

The effects of a one-percentage point increase on the aggregate of accumulated postretirement benefit obligation for health care benefits would be approximately $14.0 million, $11.3 million and $7.1 million at December 31, 2001, 2000 and 1999, respectively. The effects of a one-percentage point decrease on the aggregate of accumulated postretirement benefit obligation for health care benefits would be decreases of approximately $11.5 million, $9.4 million and $6.0 million at December 31, 2001, 2000 and 1999, respectively.

9. REPORT OF BUSINESS SEGMENTS

The Company's electric utility operations are conducted through OG&E, an operating public utility engaged in the generation, transmission, distribution and sale of electric energy. Energy supply operations are primarily conducted through Enogex. Enogex is engaged in transporting natural gas through its intra-state pipeline to various customers (including OG&E), gathering and processing natural gas, marketing electricity, natural gas and natural gas liquids and investing in the development for and production of natural gas and crude oil. Other Operations primarily includes unallocated corporate expenses and interest expense on commercial paper. Also included in Other Operations is the interest expense related to the $200 million Trust Originated Preferred Securities. The following is the Company's business segment results at December 31, 2001, 2000 and 1999.

2001	Electric Utility	Energy Supply	Other Operations	Intersegment	Total
(dollars in thousands)					
Operating revenues	**$ 1,456,802**	**$ 1,767,734**	**$ ---**	**$ (42,173) (A)**	**$ 3,182,363**
Fuel	**485,834**	**---**	**---**	**(36,317)**	**449,517**
Purchased power	**280,657**	**---**	**---**	**---**	**280,657**
Gas and electricity purchased for resale	**---**	**1,396,230**	**---**	**(5,856)**	**1,390,374**
Natural gas purchases - other	**---**	**145,595**	**---**	**---**	**145,595**
Cost of goods sold	**766,491**	**1,541,825**	**---**	**(42,173)**	**2,266,143**
Gross margin on revenues	**690,311**	**225,909**	**---**	**---**	**916,220**
Other operation and maintenance	**287,265**	**114,309**	**(9,968)**	**---**	**391,606**
Depreciation and amortization	**119,794**	**53,725**	**7,705**	**---**	**181,224**
Taxes other than income	**46,612**	**16,405**	**2,358**	**---**	**65,375**
Operating income	**236,640**	**41,470**	**(95)**	**---**	**278,015**
Other income (expenses)	**(2,463)**	**858**	**(421)**	**---**	**(2,026)**
Earnings before interest and taxes	**$ 234,177**	**$ 42,328**	**$ (516)**	**$ ---**	**$ 275,989**
Net income (loss)	**$ 121,206**	**$ (5,029)**	**$ (15,606)**	**$ ---**	**$ 100,571**
Income tax expense (benefit)	**$ 69,427**	**$ (7,127)**	**$ (9,717)**	**$ ---**	**$ 52,583**
Interest income	**$ 2,443**	**$ 3,386**	**$ 22,340**	**$ (23,768)**	**$ 4,401**
Interest expense	**$ 46,694**	**$ 57,870**	**$ 47,148**	**$ (23,768)**	**$ 127,944**

Identifiable Assets as of December 31	**$ 2,434,345**	**$ 1,520,750**	**$ 1,691,768**	**$(1,650,271)**	**$ 3,996,592**
Construction expenditures	**$ 132,300**	**$ 83,358**	**$ 9,401**	**$ ---**	**$ 225,059**

(A) Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations.

2000	Electric Utility	Energy Supply	Other Operations	Intersegment	Total
(dollars in thousands)					
Operating revenues	$ 1,453,585	$ 2,111,600	$ ---	$ (266,458) (A)	$ 3,298,727
Fuel	489,049	---	---	(37,436)	451,613
Purchased power	263,328	---	---	---	263,328
Gas and electricity purchased for resale	---	1,687,107	---	(229,022)	1,458,085
Natural gas purchases - other	---	183,134	---	---	183,134
Cost of goods sold	752,377	1,870,241	---	(266,458)	2,356,160
Gross margin on revenues	701,208	241,359	---	---	942,567
Other operation and maintenance	267,353	94,732	(8,468)	---	353,617
Depreciation and amortization	117,257	52,218	6,669	---	176,144
Taxes other than income	45,460	15,400	2,125	---	62,985
Operating income	271,138	79,009	(326)	---	349,821
Other income (expenses)	(2,745)	5,026	314	---	2,595
Earnings before interest and taxes	$ 268,393	$ 84,035	$ (12)	$ ---	$ 352,416
Net income (loss)	$ 142,392	$ 19,699	$ (15,056)	$ ---	$ 147,035
Income tax expense (benefit)	$ 80,342	$ 9,286	$ (13,123)	$ ---	$ 76,505
Interest income	$ 1,121	$ 2,878	$ 22,029	$ (22,240)	$ 3,788
Interest expense	$ 49,009	$ 57,930	$ 50,194	$ (22,240)	$ 134,893
Identifiable Assets as of December 31	$ 2,437,449	$ 1,818,917	$ 1,644,564	$(1,581,300)	$ 4,319,630
Construction expenditures	$ 128,410	$ 47,210	$ 3,851	$ ---	$ 179,471

(A) Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations.

1999	Electric Utility	Energy Supply	Other Operations	Intersegment	Total
(dollars in thousands)					
Operating revenues	$ 1,286,844	$ 1,086,027	$ 78	$ (200,515) (A)	$ 2,172,434
Fuel	350,814	---	---	(41,487)	309,327
Purchased power	249,203	---	---	---	249,203
Gas and electricity purchased for resale	---	831,309	---	(159,028)	672,281
Natural gas purchases - other	---	59,797	---	---	59,797
Cost of goods sold	600,017	891,106	---	(200,515)	1,290,608
Gross margin on revenues	686,827	194,921	78	---	881,826
Other operation and maintenance	253,312	72,759	(3,633)	---	322,438
Depreciation and amortization	119,059	41,633	4,349	---	165,041
Taxes other than income	44,892	9,416	1,874	---	56,182
Operating income	269,564	71,113	(2,512)	---	338,165
Other income (expenses)	(1,329)	2,138	(329)	---	480
Earnings before interest and taxes	$ 268,235	$ 73,251	$ (2,841)	$ ---	$ 338,645
Net income	$ 139,041	$ 21,663	$ (9,445)	$ ---	$ 151,259
Income tax expense (benefit)	$ 84,965	$ 9,834	$ (4,855)	$ ---	$ 89,944
Interest income	$ 1,710	$ 710	$ 9,218	$ (8,801)	$ 2,837
Interest expense	$ 46,658	$ 42,464	$ 20,678	$ (8,801)	$ 100,999
Identifiable Assets as of December 31	$ 2,320,660	$ 1,523,448	$ 2,086,484	$(2,009,258)	$ 3,921,334
Construction expenditures	$ 101,263	$ 48,567	$ 31,333	$ ---	$ 181,163

(A) Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations.

10. COMMITMENTS AND CONTINGENCIES

OG&E has entered into purchase commitments in connection with its construction program and the purchase of necessary fuel supplies of coal and natural gas for its generating units. The Company's construction expenditures for 2002 are estimated at $264 million.

OG&E acquires some of its natural gas for boiler fuel under a wellhead contract that contains provisions allowing the owner to require prepayments for gas if certain minimum quantities are not taken. At December 31, 2001, 2000 and 1999, outstanding prepayments for gas, including the amounts classified as current assets, under this and other prior similar contracts were approximately $39.3 million, $15.0 million and $14.9 million, respectively.

At December 31, 2001, OG&E held non-cancelable operating leases covering 1,481 coal hopper railcars. Rental payments are charged to fuel expense and recovered through OG&E's tariffs and automatic fuel adjustment clauses. The leases have purchase and renewal options. Future minimum lease payments due under the railcar leases, assuming the leases are renewed under the renewal option are as follows:

(dollars in thousands)

2002	$5,434	2005	$ 5,435
2003	5,435	2006	5,434
2004	5,435	2007 and beyond	41,390
Total Minimum Lease Payments			$ 68,563

Rental payments under the railcar operating leases were approximately $5.1 million in 2001, $5.4 million in 2000 and $4.9 million in 1999.

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

OG&E had entered into an agreement with Central Oklahoma Oil and Gas Corp. ("COOG"), an unrelated third party, to develop a natural gas storage facility. Operation of the gas storage facility proved beneficial by allowing OG&E to lower fuel costs by base loading coal generation, a less costly fuel supply. During 1996, OG&E completed negotiations and contracted with COOG for gas storage service. Pursuant to the contract, COOG reimbursed OG&E for all outstanding cash advances and interest amounting to approximately $46.8 million. OG&E also entered into a bridge financing agreement as guarantor for COOG. In July 1997, COOG obtained permanent financing and issued a note in the amount of $49.5 million. The proceeds from the permanent financing were applied to repay the outstanding bridge financing. In connection with the permanent financing, the Company entered into a note purchase agreement, where it has agreed, upon the occurrence of a monetary default by COOG on its permanent financing, to purchase COOG's note at a price equal to the unpaid principal and interest under the COOG note. In July 1998, Enogex also agreed to lease underground gas storage from COOG. This lease agreement was accounted for as a capital lease, and an asset was recorded for $26.5 million, which is being amortized over 40 years. The lease term is five years and includes seven five-year renewal options. As of December 31, 2001, 2000 and 1999, the capital lease obligation amounted to $9.3 million, $9.8 million and $10.1 million, respectively. As part of this lease transaction, the Company agreed to make up to a $12 million secured loan to an affiliate of COOG. As part of this agreement, the Company has an $8 million loan outstanding repayable in 2003 and secured by the assets and stock of COOG. This loan is classified as other property and investments in the accompanying Consolidated Balance Sheets. Disputes arose under the lease agreement between Enogex and COOG. The parties arbitrated these disputes pursuant to the terms of the lease agreement. The arbitration panel rendered a decision on February 8, 2002 ("Arbitration Award"). Pursuant to the Arbitration Award, COOG filed with the arbitration panel a Motion to Reconsider the panel's ruling. Enogex has instituted proceedings with the District Court of Oklahoma County to have the Arbitration Award confirmed and entered as a judgment of that court. The proceedings to have that award confirmed are currently subject to a protective order, under which the parties are prohibited from disclosing the terms of the Arbitration Award.

During the normal course of business, Enogex issues guarantees on behalf of OERI for the purpose of securing credit for trading activities. These guarantees are for prompt payment when due of

amounts payable by OERI under various agreements. At December 31, 2001, accounts payable supported by guarantees was $28 million. Since these guarantees by Enogex represent security for prompt payment of payables obtained in the normal course of OERI's trading activities, the Company does not assume any additional liability as a result of this arrangement.

OG&E has entered into agreements with four qualifying cogeneration facilities having initial terms of 3 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 FERC require OG&E to purchase power generated in a manufacturing process from a qualified cogeneration facility ("QF"). The rate for such power to be paid by OG&E was approved by the OCC. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by OG&E the other is a capacity charge, which OG&E must pay the QF for having the capacity available. However, if no electrical power is made available to OG&E for a period of time (generally three months), OG&E's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is recoverable in rates from customers.

During 2001, 2000 and 1999, OG&E made total payments to cogenerators of approximately $222.5 million, $227.6 million and $229.3 million, of which $190.7 million, $189.6 million and $188.8 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as purchased power. The future minimum capacity payments under the contracts for the next five years are approximately: 2002 - $191 million, 2003 - $163 million, 2004 - $151 million, 2005 - $88 million and 2006 - $86 million.

Approximately $2.3 million of the Company's construction expenditures budgeted for 2002 are to comply with environmental laws and regulations.

The Company’s management believes 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 $44.2 million during 2002, compared to approximately $42.7 million in 2001. 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.

Beginning in 2000, OG&E became subject to more stringent sulfur dioxide emissions. These lower limits had no significant financial impact due to OG&E's earlier decision to burn low sulfur coal. In 2001, OG&E's sulfur dioxide emissions were well below the allowable limits. With respect to nitrogen oxides, OG&E continues to meet the current emission standard. However, further reductions in nitrogen oxides could be required if, among other things, proposed legislation is enacted requiring further reductions, a study currently being conducted by the state of Oklahoma determines that such nitrogen oxides are contributing to regional haze, the new ozone standard survives litigation or if Oklahoma fails to meet the new fine particulate standards. Any of these scenarios would require significant capital expenditures and increased operating and maintenance costs.

In 1997, the United States was a signatory to the Kyoto Protocol on global warming. While the Protocol is not likely to be ratified by the U.S. Senate, legislation has been drafted that would limit carbon dioxide emissions. If legislation is passed this could have a tremendous impact on the Company's operations, by requiring the Company to significantly reduce the use of coal as a fuel source.

The Oklahoma Department of Environmental Quality's Clean Air Act Amendment Title V permitting program was approved by the Environmental Protection Agency ("EPA") in March 1996. By March of 1997, OG&E had submitted all required permit applications. As of December 31, 2001, OG&E had received Title V permits for all but one of its generating stations. Since OG&E submitted all its permit applications on time it is considered in compliance with the Title V permit program even though all permits have not been issued. Air permit fees for generating stations were approximately $0.5 million in 2001 and are estimated to be about the same in 2002.

On December 14, 2000, the EPA announced its decision to regulate mercury emissions from coal-fired utility boilers. Limits on the amount of mercury emitted are expected to be finalized by December 2004, although full compliance by the Company is not expected to be required until 2008. Depending upon the final regulations implemented, this could result in significant capital and operating expenditures.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the "best available technology" for minimizing environmental impacts. The EPA's original rules on this issue were set-aside in 1977 by the Fourth Circuit U.S. Court of Appeals. In 1993, EPA announced its plan to develop new rules in part due to a lawsuit filed by the Hudson Riverkeeper. To settle the lawsuit, the EPA signed a court-approved consent decree to develop 316(b) regulations on an agreed upon schedule. Proposed rules, for existing utility sources, are expected to be published soon and final rules are expected to be promulgated in August 2003. Depending on the content of the final rules, capital and operating expenses may increase at most of OG&E's generating facilities. Increased capital costs may be necessary to retrofit and/or redesign existing intake structures to comply with any new 316(b) regulations.

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against the Company and its subsidiaries. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on the Company's consolidated financial position or results of operations.

11. RATE MATTERS AND REGULATION

The OCC Staff ("Staff") annually conducts a review ("Matrix Review") to assess utility operations. The purpose of the Matrix Review is to enable the Staff to specifically identify regulated utilities that have experienced material or significant changes in operating characteristics, or in the underlying cost of service, as a means of evaluating the need to pursue rate hearings. The Staff also uses the Matrix Review to identify regulated utilities that require a Staff review of some specific operational activity conducted by the utility. The Matrix Review is composed of 11 indicators that are the basic guide for the Staff's initial review of a regulated utility. The 11 indicators include such items as the time from a utility's last rate review and service quality complaints. Each indicator is given a rating by the Staff from zero to three. A rating of zero is considered not relevant, a rating of one is considered slightly relevant, a rating of two is considered moderately relevant, while a rating of three is considered significantly relevant. The Staff believes that an aggregate rating of less than ten and with no individual indicator receiving a rating of three, should indicate that no further assessment is required. Any rating above these levels could result in a Staff recommendation requesting that a further review should be performed. In July 2001, the OCC held a hearing at which the Staff reported the results of its Matrix Review of OG&E. The review resulted in an aggregate score of 17 for OG&E, with only one indicator "Time since last formal rate review", achieving a rating of three. OG&E's last formal rate

review by the Staff occurred in 1995. As part of its written report, the Staff recommended that a general rate review be performed on OG&E.

In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of OG&E. In the filing, the Staff requested that OG&E submit information in accordance with OCC minimum standard filing requirements by January 28, 2002, for a test year ending September 30, 2001. On December 14, 2001, OG&E, citing the need for investment in security and system reliability, filed a notice with the OCC of its intent to seek an increase in OG&E's electric rates. On January 28, 2002, OG&E filed testimony with the OCC supporting OG&E's request for a $22 million rate increase. If granted, the increase would be the first for OG&E since 1985. Over the past 16 years, OG&E has had rate reductions of more than $142 million. Attempting to make security investments at the proper level, OG&E developed a set of guidelines to arrive at the appropriate steps to minimize the ability to cause 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. Approximately $10 million of the rate increase requested by OG&E was to invest in increased security. The additional $12 million is for investment in increased system reliability and for increased utility costs. OG&E has added new generation capacity to meet growing customer demand and has determined a need to increase expenditures for distribution system reliability that has been brought about, in no small part, by a series of record-breaking storms, including a 1995 windstorm in the Oklahoma City area affecting 175,000 customers, 1999 tornadoes affecting about 150,000 customers and knocking out a power plant, July 2000 thunderstorms affecting 110,000 customers, a Christmas 2000 ice storm affecting 140,000 customers, Memorial Day 2001 storms leaving 143,000 customers without power and at least two other storms affecting at least 100,000 customers each. Additionally, OG&E has experienced an overall increase in operating expenses. As part of it's filing, OG&E also is seeking approval to offer several new rate program choices to customers. One such pilot program involves flat billing. This option would set a customer's bill at a fixed dollar amount and would not change throughout the year regardless of the amount of power consumed. The bill amount would then be adjusted in the following year based on the previous year's usage and other factors. Another proposed rate program, a Green Power option, would involve OG&E contracting with wind generators to purchase a quantity of wind-generated energy, then offering that power to customers. The rate would reflect the higher cost of wind-generated power. Also included in the filing was OG&E's offer to not seek a rate increase for three years. A final order in the OG&E rate case is not expected before summer 2002.

As previously reported, certain aspects of OG&E's electric rates recently have been addressed by the OCC. In March 2000, the OCC approved, and OG&E implemented, the APC Rider reflecting the completion of the recovery of the amortization premium paid by OG&E when it acquired Enogex in 1986. The effect of the APC Rider is to remove $10.7 million annually from the amount being recovered by OG&E from its Oklahoma customers in current rates.

In June 2000, the OCC approved modifications to OG&E's Generation Efficiency Performance Rider ("GEP Rider"). The GEP Rider was established initially in 1997 in connection with OG&E's last general rate review and was intended to encourage OG&E to lower its fuel costs by: (i) allowing OG&E to collect one-third of the amount by which its fuel costs were below a specified percentage (96.261%) of the average fuel costs of certain other investor-owned utilities in the region; and (ii) disallowing the collection of one-third of the amount by which its fuel costs exceeded a specified percentage (103.739%) of the average fuel costs of other investor-owned utilities. The modifications enacted in June 2000 had the effect of reducing the amount OG&E could recover under the GEP Rider by: (i) changing OG&E's peer group to include utilities with a higher coal-to-gas generation mix; (ii) reducing the amount of fuel costs that can be recovered if OG&E's costs exceed the new peer group by changing the percentage above

which OG&E will not be allowed to recover one-third of the fuel costs from Oklahoma customers from 103.739 percent to 101.0 percent; (iii) reducing OG&E's share of cost savings as compared to its new peer group from 33 percent to 30 percent; and (iv) limiting to $10.0 million the amount of any awards paid to OG&E or penalties charged to OG&E. For the period between July 1, 2001 and June 30, 2002, the Company estimates that it will recover $5.1 million under the GEP Rider. The GEP Rider is scheduled to expire in June 2002, however, the OCC could decide to establish a similar reward mechanism in a subsequent action upon proper showing.

The final action addresses the competitive bid process of OG&E's gas transportation needs following which OG&E's affiliate, Enogex, contracted to provide gas transportation service to all of OG&E's generation plants. In the 1997 Order, the OCC approved a stipulation wherein OG&E agreed to initiate a competitive bidding process for gas transportation service to its gas-fired plants, with the competitive services commencing no later than April 30, 2000. The order also set annual compensation for the transportation services provided by Enogex to OG&E at $41.3 million annually until March 1, 2000, at which time the rate would drop to $28.5 million (reflecting removal of the APC Rider, upon the completion of the recovery from customers of the amortization premium paid by OG&E when it acquired Enogex in 1986) and remain at that level until competitively-bid gas transportation began. Final firm bids were submitted by Enogex and other pipelines on April 15, 1999. In July 1999, OG&E filed an application with the OCC requesting approval of a performance-based rate plan for its Oklahoma retail customers from April 2000 until the introduction of customer choice for electric power in July 2002. As part of this application, OG&E stated that Enogex had submitted the only viable bid ($33.4 million per year) for gas transportation to OG&E's six gas-fired power plants that were the subject of the competitive bid. As part of its application to the OCC, OG&E offered to discount Enogex's bid from $33.4 million annually to $25.2 million annually. OG&E executed a gas transportation contract with Enogex under which Enogex continues to serve the needs of OG&E's power plants at a price to be paid by OG&E of $33.4 million annually and, if OG&E's proposal had been approved by the OCC, OG&E would have recovered a portion of such amount ($25.2 million) from its customers. OG&E negotiated with the Staff, the Office of the Oklahoma Attorney General and a coalition of industrial customers in an effort to settle all issues (including the competitive bid process) associated with its application for a performance-based rate plan. When these negotiations failed, OG&E withdrew its application, which withdrawal was approved by the OCC in December 1999.

In July 2000, OG&E entered into a stipulation (the "Stipulation") with the Staff, the Office of the Attorney General and a coalition of industrial customers regarding the competitive bid process of OG&E's gas transportation service. In June 2001, the OCC approved the Stipulation declaring the Stipulation to be fair, just and reasonable and representing a reasonable settlement of the issues and thereby serving the public interest. OG&E had previously collected $28.5 million on an annual basis through its base rate and APC Rider for gas transportation services from Enogex for the power plant requirements covered by the competitive bid. The Stipulation permits OG&E to recover $25.2 million annually for the gas transportation services provided by Enogex pursuant to the competitive bid process. The Stipulation directs OG&E to reduce rates to its Oklahoma retail customers by approximately $2.7 million per year through the implementation of a GTAC Rider. The GTAC Rider is a credit for gas transportation cost recovery and is applicable to and becomes part of each Oklahoma retail rate schedule to which OG&E's Fuel Cost Adjustment rider applies. The GTAC Rider became effective with the first billing cycle of July 2001, and will remain in effect until amended by OG&E at the direction of the OCC.

On February 13, 1998, the APSC staff filed a motion for a show cause order to review OG&E's electric rates in the State of Arkansas. The Staff recommended a $3.1 million annual rate reduction (based on a test year ended December 31, 1996). The Staff and OG&E reached a settlement for a $2.3 million annual rate reduction, which was approved by the APSC in August 1999.

12. DISCLOSURES ABOUT FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of Long-Term Debt and Preferred Securities is estimated based on quoted market prices and management's estimate of current rates available for similar issues. The fair value of the Enogex Notes is based on management's estimate of current rates available for similar issues with the same remaining maturities.

Indicated below are the carrying amounts and estimated fair values of the Company's financial instruments as of December 31:

	2001		2000		1999	
(dollars in thousands)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt and Preferred Securities:						
Senior Notes...........................	**$564,979**	**$571,426**	$567,182	$552,256	$457,646	$422,181
Industrial Authority Bonds............	**135,400**	**135,400**	135,400	135,400	135,400	135,400
Enogex Inc. Notes......................	**625,924**	**666,695**	745,941	797,766	347,486	410,578
Trust Originated Preferred Securities..	**200,000**	**200,000**	200,000	200,000	200,000	200,000

13. SUBSEQUENT EVENTS

In January 2002, the Company's line of credit for $200 million was renewed for $195 million, with an expiration date of January 19, 2003.

On January 28, 2002, OG&E filed testimony with the OCC supporting OG&E's request for a $22 million rate increase. If granted, the increase would be the first for OG&E since 1985.

In January 2002, a significant ice storm hit the OG&E service territory. This ice storm inflicted major damage to the transmission and distribution infrastructure. Total expenditures are currently estimated at $136 million. The vast majority of these expenditures for restoration of the utility's system will be capitalized as part of the utility's plant. The Company believes its short-term borrowing capacity is adequate to finance the restoration of the system. The area of damage is within counties that were declared a federal disaster area. OG&E intends to pursue a plan with the OCC to seek recovery of this cost in future rates as part of the existing rate proceeding, which may delay the final order establishing new rates to be issued by the OCC.

Enogex Products Corporation ("EPC") will sell all common stock and interest in Belvan Corporation, Belvan Limited Partnership and Todd Ranch Limited Partnership to West Texas Gas, Inc. The Closing date is scheduled for March 28, 2002, with an effective date of January 1, 2002. EPC will retain control of operations of the entities through March 31, 2002. Belvan Limited Partnership and Todd Ranch Limited Partnership had approximately 344 miles of gathering lines in Crockett and Pecos counties in Texas.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

ARTHUR ANDERSEN

To the Shareowners of
OGE Energy Corp.:

We have audited the accompanying consolidated balance sheets and statements of capitalization of OGE Energy Corp. (an Oklahoma corporation) and subsidiaries as of December 31, 2001, 2000 and 1999, and the related consolidated statements of income, retained earnings, comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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 financial position of OGE Energy Corp. and subsidiaries as of December 31, 2001, 2000 and 1999, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States.

/s/ Arthur Andersen LLP
Arthur Andersen LLP

Oklahoma City, Oklahoma,
January 24, 2002

REPORT OF MANAGEMENT

To Our Shareowners:

The management of OGE Energy Corp. is responsible for the preparation, integrity and objectivity of the consolidated financial statements of the Company and its subsidiaries and other information included in this report. The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States. As appropriate, the statements include amounts based on informed estimates and judgments of management.

The management of the Company has established and maintains a system of internal control designed to provide reasonable assurance, on a cost-effective basis, that assets are safeguarded, transactions are executed in accordance with management's authorization and financial records are reliable for preparing consolidated financial statements. Management believes that the system of control provides reasonable assurance that errors or irregularities that could be material to the consolidated financial statements are prevented or would be detected within a timely period. Key elements of this system include the effective communication of established written policies and procedures, selection and training of qualified personnel and organizational arrangements that provide an appropriate division of responsibility. This system of control is augmented by an ongoing internal audit program designed to evaluate its adequacy and effectiveness. Management considers the recommendations of the internal auditors and independent public accountants concerning the Company's system of internal control and takes timely and appropriate actions to alleviate their concerns. Management believes that as of December 31, 2001, the Company's system of internal control was adequate to accomplish the objectives discussed herein.

The Board of Directors of the Company addresses its oversight responsibility for the consolidated financial statements through its Audit Committee, which is composed of directors who are not employees of the Company. The Audit Committee meets regularly with the Company's management, internal auditors and independent public accountants to review matters relating to financial reporting, auditing and internal control. To ensure auditor independence, both the internal auditors and independent public accountants have full and free access to the Audit Committee.

The independent public accounting firm of Arthur Andersen LLP is engaged to audit, in accordance with auditing standards generally accepted in the United States, the consolidated financial statements of the Company and its subsidiaries and to issue their report thereon.

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

/s/ Al M. Strecker
Al M. Strecker, Executive Vice President and Chief Operating Officer

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

/s/ Donald R. Rowlett
Donald R. Rowlett, Vice President and Controller

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 for a fair statement of the results of operations for such periods:

Quarter ended (dollars in thousands except per share data)		Dec 31	Sep 30	Jun 30	Mar 31
Operating revenues	**2001**	**$ 543,119**	**$ 827,766**	**$ 747,891**	**$ 1,063,587**
	2000	982,276	1,007,966	726,904	581,581
	1999	575,978	767,390	450,861	378,205
Operating income	**2001**	**$ 14,059**	**$ 187,595**	**$ 69,761**	**$ 6,600**
	2000	40,819	205,060	71,746	32,196
	1999	50,570	180,373	73,147	34,075
Net income (loss)	**2001**	**$ (6,306)**	**$ 97,053**	**$ 24,793**	**$ (14,969)**
	2000	7,208	107,307	31,744	776
	1999	12,179	90,204	37,744	11,132
Earnings (loss) available for common stock	**2001**	**$ (6,306)**	**$ 97,053**	**$ 24,793**	**$ (14,969)**
	2000	7,208	107,307	31,744	776
	1999	12,179	90,204	37,744	11,132
Earnings (loss) per average common share	**2001**	**$ (0.09)**	**$ 1.25**	**$ 0.32**	**$ (0.19)**
	2000	0.09	1.38	0.41	0.01
	1999	0.15	1.16	0.49	0.14

DIVIDENDS

COMMON STOCK

Common quarterly dividends paid (as declared) in 2001, 2000, and 1999 were $0.33 1/4.
Present rate-$0.33 1/4
Payable 30th of January, April, July, and October

SECURITY RATINGS*

	Moody's	Standard and Poor's	Fitch's
OG&E Senior Notes	A1	A-	AA-
Enogex Notes	Baa2	A-	BBB
OGE Energy Corp. Commercial Paper	P-2	A-2	F1

*The ratings of Moody's, Standard and 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 purchase, sell or hold a security. There can be no assurance that such ratings will remain in effect for any

given period of time or that they will not be revised downward or withdrawn entirely by either of such rating agencies if, in the judgment of either circumstances so warrant. Standard and Poor's currently maintains a negative outlook on its ratings of OG&E Senior Notes and Enogex Notes. Moody's currently maintains a negative outlook on its rating of Enogex Notes.

For further information regarding these ratings, please contact the Secretary of the Company at P. O. Box 321, Oklahoma City, Oklahoma 73101-0321, (405) 553-3196.

MARKET PRICES

	2001		2000	
NEW YORK STOCK EXCHANGE	**High**	**Low**	High	Low
Common				

First Quarter	**$24.69**	**$21.25**	$20.88	$16.50
Second Quarter	**23.77**	**20.80**	21.25	18.31
Third Quarter	**23.48**	**20.25**	23.25	18.75
Fourth Quarter	**23.41**	**20.95**	24.75	18.94

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

Not Applicable.

PART III

Item 10. Directors and Executive Officers of the Registrant.

Item 11. Executive Compensation.

Item 12. Security Ownership of Certain Beneficial Owners and Management.

Item 13. Certain Relationships and Related Transactions.

Items 10, 11, 12 and 13 are omitted pursuant to General Instruction G of Form 10-K, since the Company will file copies of a definitive proxy statement with the Securities and Exchange Commission on or about April 4, 2002. Such proxy statement is incorporated herein by reference. In accordance with Instruction G of Form 10-K, the information required by Item 10 relating to Executive Officers has been included in Part I, Item 4, of this Form 10-K.

PART IV

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K.

(a) 1. Financial Statements

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

- Consolidated Balance Sheets at December 31, 2001, 2000 and 1999
- Consolidated Statements of Capitalization at December 31, 2001, 2000 and 1999
- Consolidated Statements of Income for the years ended December 31, 2001, 2000 and 1999
- Consolidated Statements of Retained Earnings for the years ended December 31, 2001, 2000 and 1999
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2001, 2000 and 1999
- Consolidated Statements of Cash Flows for the years ended December 31, 2001, 2000 and 1999
- Notes to Consolidated Financial Statements
- Report of Independent Public Accountants
- Report of Management

Supplementary Data

- Interim Consolidated Financial Information

2. Financial Statement Schedule (included in Part IV)	Page
Schedule II - Valuation and Qualifying Accounts	95
Report of Independent Public Accountants	96

All other schedules have been omitted since the required information is not applicable or is not material, or because the information required is included in the respective financial statements or notes thereto.

3. Exhibits

Exhibits No.	Description
2.01	Purchase Agreement, dated as of May 14, 1999, by and between Tejas Gas, LLC and Enogex Inc. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended

June 30, 1999 (File No. 1-12579) and incorporated by reference herein)

3.01 Copy of Restated Certificate of Incorporation. (Filed as Exhibit 3.01 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

3.02 By-laws. (Filed as Exhibit 3.02 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

4.01 Copy of Trust Indenture dated October 1, 1995, from OG&E to Boatmen's First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to Registration Statement No. 33-61821 and incorporated by reference herein)

4.02 Copy of Supplemental Trust Indenture No. 1 dated October 16, 1995, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K Report dated October 23, 1995, (File No. 1-1097), and incorporated by reference herein)

4.03 Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed on July 17, 1997, (File No. 1-1097) and incorporated by reference herein)

4.04 Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed on April 16, 1998 (File No. 1-1097) and incorporated by reference herein)

4.05 Supplemental Indenture No. 4, dated as of October 15, 2000, being a supplement instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed on October 20, 2000 (File No. 1-1097) and incorporated by reference herein)

10.01 Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company. (Filed as Exhibit 5.19 to Registration Statement No. 2-59887 and incorporated by reference herein)

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10.10 Company's Annual Incentive Compensation Plan. (Filed as Exhibit 10.12 to OGE Energy's Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)

10.11 OGE Energy Corp. Deferred Compensation Plan. (Filed as Exhibit 4 to the Company's Form S-8 Registration Statement No. 333-92433 and incorporated by reference herein)

10.12 Copy of Amended and Restated Rights Agreement, dated as of October 10, 2000 between OGE Energy Corp. and Chase Mellon Shareholder Services, LLC, as Rights Agent (Filed as Exhibit 4.1 to OGE Energy's Form 8-K filed on November 1, 2000 (File No. 1-12579) and incorporated by reference herein)

10.13 OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to OGE Energy's Form 10-K for the Year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

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21.01 Subsidiaries of the Registrant.

23.01 Consent of Arthur Andersen LLP.

24.01 Power of Attorney.

99.01 Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995.

99.02 Representation by Arthur Andersen LLP in connection with audit of OGE Energy Corp.

<u>Executive Compensation Plans and Arrangements</u>

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Exhibit 10.14 to OGE Energy's Form 10-K for the
Year ended December 31, 2000 (File No. 1-12579)
and incorporated by reference herein)

(b) Reports on Form 8-K

No reports on Form 8-K were filed during the quarter ended December 31, 2001.

OGE ENERGY CORP.

SCHEDULE II - Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
		(Thousands)			
Year Ended December 31, 1999					
Reserve for Uncollectible Accounts	$ 3,342	$ 9,560	-	$ 7,632(1)	$ 5,270
Year Ended December 31, 2000					
Reserve for Uncollectible Accounts	$ 5,270	$ 7,262	-	$ 8,397(1)	$ 4,135
Year Ended December 31, 2001					
Reserve for Uncollectible Accounts	$ 4,135	$18,057	-	$13,329(1)	$ 8,863

(1) Uncollectible accounts receivable written off, net of recoveries.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To OGE Energy Corp.:

We have audited in accordance with auditing standards generally accepted in the United States, the consolidated financial statements of OGE Energy Corp. (an Oklahoma Corporation), and its subsidiaries included in this Form 10-K, and have issued our report thereon dated January 24, 2002. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedule listed on Page 90 Item 14 (a) 2. is the responsibility of the Company's management and is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

/s/ Arthur Andersen LLP
Arthur Andersen LLP

Oklahoma City, Oklahoma,
January 24, 2002

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, and State of Oklahoma on the 27th day of March, 2002.

OGE ENERGY CORP.
(REGISTRANT)

/s/ Steven E. Moore
By Steven E. Moore

Chairman of the Board, President
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this Report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/ s / Steven E. Moore Steven E. Moore	Principal Executive Officer and Director;	March 27, 2002
/ s / James R. Hatfield James R. Hatfield	Principal Financial Officer; and	March 27, 2002
/ s / Donald R. Rowlett Donald R. Rowlett	Principal Accounting Officer.	March 27, 2002

Herbert H. Champlin	Director;
Luke R. Corbett	Director;
William E. Durrett	Director;
Martha W. Griffin	Director;
Hugh L. Hembree, III	Director;
Robert Kelley	Director;
Ronald H. White, M.D.	Director; and
J. D. Williams	Director.

/ s / Steven E. Moore
By Steven E. Moore (attorney-in-fact) March 27, 2002

Exhibit Index

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24.01 Power of Attorney.

99.01 Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

99.02 Representations by Arthur Andersen LLP in connection with audit of OGE Energy Corp.

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Exhibit 21.01

OGE Energy Corp.
Subsidiaries of the Registrant

Name of Subsidiary	Jurisdiction of Incorporation	Percentage of Ownership
Oklahoma Gas and Electric Company	Oklahoma	100.0
Enogex Inc.	Oklahoma	100.0
Enogex Products Corporation	Oklahoma	100.0
OGE Energy Resources Inc.	Oklahoma	100.0
Enogex Exploration Corporation	Oklahoma	100.0
OGE Energy Capital Trust I	Oklahoma	100.0

The above listed subsidiaries have been consolidated in the Registrant's financial statements.

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Exhibit 23.01

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our reports dated January 24, 2002 included in the OGE Energy Corp. Form 10-K for the year ended December 31, 2001, into the previously filed Post-Effective Amendment No. 1-B to Registration Statement No. 33-61699, Post-Effective Amendment No. 2-B to Registration Statement No. 33-61699, Form S-8 Registration Statement No. 333-71327 and Form S-8 Registration Statement No. 333-92423.

/s/ Arthur Andersen LLP
Arthur Andersen LLP

Oklahoma City, Oklahoma,
March 27, 2002

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Exhibit 24.01

POWER OF ATTORNEY

WHEREAS, OGE ENERGY CORP., an Oklahoma corporation (herein referred to as the "Company"), is about to file with the Securities and Exchange Commission, under the provisions of the Securities Exchange Act of 1934, as amended, its annual report on Form 10-K for the year ended December 31, 2001; and

WHEREAS, each of the undersigned holds the office or offices in the Company herein-below set opposite his or her name, respectively;

NOW, THEREFORE, each of the undersigned hereby constitutes and appoints STEVEN E. MOORE, JAMES R. HATFIELD and DONALD R. ROWLETT and each of them individually, his or her attorney with full power to act for him or her and in his or her name, place and stead, to sign his name in the capacity or capacities set forth below to said Form 10-K and to any and all amendments thereto, and hereby ratifies and confirms all that said attorney may or shall lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this 16th day of January 2002.

Steven E. Moore, Chairman, Principal Executive Officer and Director	/ s / Steven E. Moore
Herbert H. Champlin, Director	/ s / Herbert H. Champlin
Luke R. Corbett, Director	/ s / Luke R. Corbett
William E. Durrett, Director	/ s / William E. Durrett
Martha W. Griffin, Director	/ s / Martha W. Griffin
Hugh L. Hembree, III, Director	/ s / Hugh L. Hembree, III
Robert Kelley, Director	/ s / Robert Kelley
Ronald H. White, M.D., Director	/ s / Ronald H. White, M.D.
J.D. Williams, Director	/ s / J.D. Williams
James R. Hatfield, Principal Financial Officer	/ s / James R. Hatfield
Donald R. Rowlett, Principal Accounting Officer	/ s / Donald R. Rowlett

STATE OF OKLAHOMA)
) SS
COUNTY OF CANADIAN)

On the date indicated above, before me, Debra Peters, Notary Public in and for said County and State, personally appeared the above named directors and officers of OGE ENERGY CORP., an Oklahoma corporation, and known to me to be the persons whose names are subscribed to the foregoing instrument, and they severally acknowledged to me that they executed the same as their own free act and deed.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal on the 16th day of January, 2002.

/s/ Debra Peters
Debra Peters
Notary Public in and for the County
of Canadian, State of Oklahoma

My Commission Expires:
May 3, 2003

Exhibit 99.01

OGE Energy Corp. Cautionary Factors

The Private Securities Litigation Reform Act of 1995 provides a "safe harbor" for forward-looking statements to encourage such disclosures without the threat of litigation providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements have been and will be made in written documents and oral presentations of OGE Energy Corp. (the "Company"). Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used in the Company's documents or oral presentations, the words "anticipate", "estimate", "expect", "objective" and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company's actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Increased competition in the utility industry, including effects of: decreasing margins as a result of competitive pressures; industry restructuring initiatives, including state legislation providing for retail customer choice of electricity providers; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;
- Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, transmission, currency, interest rate and warranty risks;
- Risks associated with price risk management strategies intended to mitigate exposure to adverse movement in the prices of electricity and natural gas on both a global and regional basis, including commodity price changes, market supply shortages, interest rate changes and counter party default;
- Economic conditions including inflation rates and monetary fluctuations;
- Customer business conditions including demand for their products or services and supply of labor and materials used in creating their products and services;
- Financial or regulatory accounting principles or policies imposed by the Financial Accounting Standards Board, the Securities and Exchange Commission, the Federal Energy Regulatory Commission, state public utility commissions, state entities which regulate natural gas transmission, gathering and processing and similar entities with regulatory oversight;
- Availability or cost of capital such as changes in: interest rates, market perceptions of the utility and energy-related industries, the Company or any of its subsidiaries or security ratings;
- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, unusual maintenance or repairs; unanticipated changes to fossil fuel or gas supply costs or availability due to higher demand, shortages,

transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints;

- Employee workforce factors including changes in key executives, collective bargaining agreements with union employees, or work stoppages;
- Rate-setting policies or procedures of regulatory entities, including environmental externalities;
- Social attitudes regarding the utility, natural gas and power industries;
- Identification of suitable investment opportunities to enhance shareowner returns and achieve long-term financial objectives through business acquisitions;
- Some future investments made by the Company could take the form of minority interests which would limit the Company’s ability to control the development or operation of an investment;
- Costs and other effects of legal and administrative proceedings, settlements, investigations, claims and matters, including but not limited to those described in Note 10 of Notes to Consolidated Financial Statements of the Company’s Annual Report on Form 10-K for the year ended December 31, 2001, under the caption Commitments and Contingencies;

- Technological developments, changing markets and other factors that result in competitive disadvantages and create the potential for impairment of existing assets;

- Other business or investment considerations that may be disclosed from time to time in the Company's Securities and Exchange Commission filings or in other publicly disseminated written documents.

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

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

OG+E
[LOGO]

EXHIBIT 99.02

March 28, 2002

Securities and Exchange Commission
450 Fifth Street, N.W.
Washington, D.C. 20549

Re: Representations by Arthur Andersen LLP
in connection with audit of OGE Energy Corp.

Ladies and Gentlemen:

On behalf of OGE Energy Corp. (the "Comapny"), please be advised that Arthur Andersen LLP ("Andersen") has represented to the Company that its audit of the Company's consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2001, to which this letter is an exhibit, was subject to Andersen's quality control system for the U.S. accounting and auditing practice to provide reasonable assurance that the engagement was conducted in compliance with professional standards and that there was appropriate continuity of Andersen personnel working on the audit, availability of national office consultation and availability of personnel at foreign affiliates of andersen to conduct the relevant portions of the audit.

Sincerely,

/s/ Donald R. Rowlett

Donald R. Rowlett
Vice President and Controller