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 1-1097

Oklahoma Gas and Electric Company meets the conditions set forth in General Instruction I (1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format permitted by General Instruction I (2).

OKLAHOMA GAS AND ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oklahoma	**73-0382390**
(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: None

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 deliquent 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, the number of outstanding shares of the Registrant's common stock, par value $2.50 per share, was 40,378,745 all of which were held by OGE Energy Corp. There were no other shares of capital stock of the Registrant outstanding at such date.

DOCUMENTS INCORPORATED BY REFERENCE
None

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PART I

Item 1. Business.

THE COMPANY

Introduction

Oklahoma Gas and Electric Company (the "Company") is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity to retail and wholesale customers in Oklahoma and western Arkansas. The Company is a wholly-owned subsidiary of OGE Energy Corp. ("Energy Corp.") which 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's executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone (405) 553-3000.

The Company was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in the State of Oklahoma. The Company owns and operates eight generating stations with a total capability of 5,732 megawatts. At the end of 2001, the Company had 1,997 members.

In September 2001, the director of the Oklahoma Corporation Commission ("OCC") public utility division filed an application with the OCC to review the rates of the Company. The Company's rates had last been formally reviewed in 1995. In the filing, the OCC requested that the Company 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, the Company filed its response requesting a $22 million annual rate increase. The Company'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 the Company requested a rate increase. A final order in the Company's 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 financial position or results of operation. See "Regulation and Rates - Recent Regulatory Matters" for further discussion of these developments.

The Company's 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 the Company. 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 "Regulation and Rates - State Restructuring Initiatives" for further discussion of these developments.

General

The Company 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 the Company 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.

The Company's system control area peak demand as reported by the system dispatcher for the year was approximately 5,788 megawatts on July 12, 2001. The Company'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 below and in the operating statistics on page 3, 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 the Company'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%)

The Company 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, the Company 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 "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

Finance and Construction

The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings from Energy Corp. 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 for 2001 and as estimated for 2002 through 2004 are as follows:

(dollars in millions)	**2001**	2002	2003	2004
Construction expenditures including AFUDC..........	**$132.3**	$221.0	$113.0	$116.0

In January 2002, a significant ice storm hit the Company's service territory and inflicted major damage to the transmission and distribution infrastructure. Total expenditures are currently estimated at $136 million. The Company's 2002 construction expenditures in the above chart include the costs for restoration of the transmission and distribution infrastructure. 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. The Company 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. 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 its customers during the foreseeable future, the Company 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. The Company 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 from Energy Corp. to meet temporary cash requirements. The Company has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time. At December 31, 2001, Energy Corp. 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, Energy Corp.'s $200 million line of credit was renewed for $195 million, with an expiration date of January 9, 2003. Energy Corp.'s short-term borrowings will consist of some combination of bank borrowings and commercial paper. Energy Corp.'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 Energy Corp. 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 did not have any short-term debt outstanding at December 31, 2001. The Company had $39.2 million and $55.5 million in short-term debt outstanding at December 31, 2000 and 1999, respectively.

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

Regulation and Rates

The Company's retail electric tariffs in Oklahoma are regulated by the OCC, and in Arkansas by the Arkansas Public Service Commission ("APSC"). The issuance of certain securities by the Company is also regulated by the OCC and the APSC. The Company's wholesale electric tariffs, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). The Secretary of the Department of Energy has jurisdiction over some of the Company's facilities and operations.

The order of the OCC authorizing the Company to reorganize into a subsidiary of Energy Corp. contains certain provisions which, among other things, ensure the OCC access to the books and records of Energy Corp. and its affiliates relating to transactions with the Company; require the Company to employ accounting and other procedures and controls to protect against subsidization of non-utility activities by the Company's customers; and prohibit the Company from pledging its assets or income for affiliate transactions.

For the year ended December 31, 2001, approximately 87 percent of the Company's 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 the Company. The review resulted in an aggregate score of 17 for the Company, with only one indicator "Time since last formal rate review", achieving a rating of three. The Company'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 the Company.

In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of the Company. In the filing, the Staff requested that the Company 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, the Company, citing the need for investment in security and system reliability, filed a notice with the OCC of its intent to seek an increase

in the Company's electric rates. On January 28, 2002, the Company filed testimony with the OCC supporting the Company's request for a $22 million annual rate increase. If granted, the increase would be the first for the Company since 1985. Over the past 16 years, the Company has had rate reductions of more than $142 million. Attempting to make security investments at the proper level, the Company 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 the Company 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 the Company was to invest in increased security. The additional $12 million is for investment in increased system reliability and for increased utility costs. The Company 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, the Company has experienced an overall increase in operating expenses. As part of it's filing, the Company 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 the Company 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 the Company's offer to not seek a rate increase for three years. A final order in the Company's rate case is not expected until later in 2002.

In January 2002, a significant ice storm hit the Company's service territory and 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 transmission and distribution infrastructure will be capitalized as part of 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 the Company's electric rates recently have been addressed by the OCC. In March 2000, the OCC approved, and the Company implemented, the Acquisition Premium Credit Rider ("APC Rider") reflecting the completion of the recovery of the amortization premium paid by the Company when it acquired Enogex Inc. ("Enogex") in 1986. The effect of the APC Rider is to remove $10.7 million annually from the amount being recovered by the Company from its Oklahoma customers in current rates.

In June 2000, the OCC approved modifications to the Company's Generation Efficiency Performance Rider ("GEP Rider"). The GEP Rider was established initially in 1997 in connection with the Company's last general rate review and was intended to encourage the Company to lower its fuel costs by: (i) allowing the Company 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 the Company could recover

under the GEP Rider by: (i) changing the Company'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 the Company's costs exceed the new peer group by changing the percentage above which the Company 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 the Company'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 the Company or penalties charged to the Company. 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 the Company's gas transportation needs following which the Company's affiliate, Enogex, contracted to provide gas transportation service to all of the Company's generation plants. In the 1997 Order, the OCC approved a stipulation wherein the Company 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 the Company 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 the Company 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, the Company 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, the Company stated that Enogex had submitted the only viable bid ($33.4 million per year) for gas transportation to the Company's six gas-fired power plants that were the subject of the competitive bid. As part of its application to the OCC, the Company offered to discount Enogex's bid from $33.4 million annually to $25.2 million annually. The Company executed a gas transportation contract with Enogex under which Enogex continues to serve the needs of the Company's power plants at a price to be paid by the Company of $33.4 million annually and, if the Company's proposal had been approved by the OCC, the Company would have recovered a portion of such amount ($25.2 million) from its customers. The Company 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, the Company withdrew its application, which withdrawal was approved by the OCC in December 1999.

In July 2000, the Company 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 the Company'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. The Company 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 the Company to recover $25.2 million annually for the gas transportation services provided by Enogex pursuant to the competitive bid process. The Stipulation directs the Company 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 the Company'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 the Company at the direction of the OCC.

On February 13, 1998, the APSC staff filed a motion for a show cause order to review the Company'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 the Company 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, will significantly affect the Company's future operations. The Company'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. The Company 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 the Company'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 the Company when it acquired Enogex in 1986. The GTAC Rider and the APC Rider are both applicable to each Oklahoma retail rate schedule to which the Company's fuel cost adjustment clause applies.

National Energy Legislation

Federal law imposes numerous responsibilities and requirements on the Company. The Public Utility Regulatory Policies Act of 1978 requires electric utilities, such as the Company, 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. The Company 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 the Company, 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. 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 the Company) 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.

The Company is a member of the Southwest Power Pool ("SPP"), the regional reliability organization for Oklahoma, Arkansas, Kansas, Louisiana, Missouri and part of Texas. The Company 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. The Company 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 the Company'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, the Company anticipates that it will join the MISO. The transfer of operational control of the Company's transmission system to a FERC-approved RTO is not expected to significantly impact the Company's financial results. Yet, it is expected to increase the markets in which the Company 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, the Company 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 the Company has historically integrated its load and resources. Under NTS, the Company 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 the Company'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 the Company'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.

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. The Company has taken steps in the past and intends to take appropriate steps in the future to remain a competitive supplier of electricity. While the Company is supportive of competition, it believes that all electric suppliers must be required to compete on a fair and equitable basis and the Company is advocating this position vigorously.

Rate Activities and Proposals

As previously discussed, the OCC initiated a rate review proceeding for the Company 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 the Company 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 the Company's stakeholders.

The Company 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 the Company'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 the Company's commercial and industrial customers is voluntary load curtailment. This program will provide customers with the opportunity to curtail on a voluntary basis when the Company's 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.

The Company 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.

The Company has proposed the Transmission Investment Recovery Rider ("TIR Rider") which would be applicable to investments necessary for increased transmission service 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. The Company 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 the Company would be required to pay for certain types of transmission upgrades to the system, the Company 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 the Company'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 re-determined.

The Company also is proposing a Coal Utilization Performance Rider ("CUP Rider"), the Cup Rider is designed to reward the Company based on its performance in the utilization of its coal generation facilities. The greater the coal plant utilization, the greater the benefits received by the Company's customers. The Company'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 the Company by encouraging the Company 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 the Company all benefit if the Company is able to increase coal plant utilization.

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

Fuel Supply

During 2001, approximately 73 percent of the Company-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 "Regulation and Rates - Automatic Fuel Adjustment Clauses."

<u>Coal-Fired Units:</u> All of the Company's coal units, with an aggregate capability of 2,539 megawatts, are designed to burn low sulfur western coal. The Company purchases coal primarily under long-term contracts. During 2001, the Company 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, the Company 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, the Company 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.

The Company 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 the Company's ability to use coal as its primary boiler fuel.

<u>Gas-Fired Units:</u> The Company utilizes a Request for Bid to acquire natural gas supplies. For calendar year 2002, successful bids were

accepted that are expected to supply approximately 70 percent of the Company's estimated annual gas requirements. The additional gas requirements will be secured through monthly and day-to-day purchases as needed.

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

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"), the Company has completed installation and certification of all required continuous emissions monitors at its generating stations. The Company submits emissions data quarterly to the Environmental Protection Agency ("EPA") as required by the CAAA. Phase II sulfur dioxide ("SO2") emission requirements affected the Company beginning in the year 2000. The Company met the SO2 limits without additional capital expenditures due to the Company's earlier decision to purchase low sulfur coal. In 2001, the Company'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, the Company was eligible to exercise its option to extend the effective date of the lower emission

requirements from the year 2000 until 2008. The Company's average NOx emissions from its coal-fired boilers for 2001 was 0.33 lbs/MMBtu.

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

Other potential air regulations have emerged that could impact the Company. 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.

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 the Company'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 the Company.

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 Generation 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 the Company's operations, by requiring the Company to significantly reduce the use of coal as a fuel source.

The Company 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, the Company 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.

The Company 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, the Company has made application for a new OPDES permit to cover gas turbine generating units that were constructed at one of its existing plants.

The Company 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, the Company facility could be subjected to costly treatment and/or facility reconfiguration requirements. Both the State and the EPA have now approved this request.

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 financial position or results of operations.

Item 2. Properties.

The Company 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, the Company'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. The Company'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.

During the three years ended December 31, 2001, the Company's gross property, plant and equipment additions approximated $362.0 million and gross retirements approximated $94 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 9.6 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 the Company of its intent to purchase the Company's electric distribution facilities for Enid and to terminate the Company'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 the Company 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, the Company 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 the Company the option to acquire the Company'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) the Company's support of the Enid Citizens' Against the Government Takeover was improper; (v) the Company has violated the favored nations clause of the existing franchise; and (vi) the City of Enid and the Company 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 the Company's property to be transferred to the Company for inadequate consideration. Plaintiffs demand judgment for treble the value of the property allegedly wrongfully transferred to the Company. On October 28, 1997, another resident filed a similar lawsuit against the Company, 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, the Company 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 the Company. (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 the Company, 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.

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

Under the reduced disclosure format permitted by General Instruction I(2)(c) of Form 10-K, the information otherwise required by this item has been omitted.

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
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
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 Energy Corp. Each Officer is to hold office until the Board of Directors meeting following the next annual meeting 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
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

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
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
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.

Currently, all Company common stock, 40,378,745 shares, is held by Energy Corp. Therefore, there is no public trading market for the Company's common stock.

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.................	**$1,456,802**	$1,453,585	$1,286,844	$1,312,078	$1,191,690
Cost of goods sold.................	**766,491**	752,377	600,017	597,323	541,958
Gross margin on revenues...........	**690,311**	701,208	686,827	714,755	649,732
Other operating expenses...........	**453,671**	430,070	417,263	398,958	403,694
Operating income...................	**236,640**	271,138	269,564	315,797	246,038
Other income (expenses)............	**(2,463)**	(2,745)	(1,329)	(5)	3,627
Interest expense, net..............	**(43,544)**	(45,659)	(44,229)	(48,871)	(55,947)
Earnings before income taxes.......	**190,633**	222,734	224,006	266,921	193,718
Income tax expense.................	**69,427**	80,342	84,965	106,583	72,724
Net income.........................	**121,206**	142,392	139,041	160,338	120,994
Preferred dividend requirements....	**---**	---	---	733	2,285
Earnings available for common......	**$ 121,206**	$ 142,392	$ 139,041	$ 159,605	$ 118,709
Long-term debt.....................	**$ 700,379**	$ 702,582	$ 593,045	$ 702,912	$ 691,924
Total assets.......................	**$ 2,434,345**	$2,437,449	$2,320,660	$2,320,097	$2,350,782
CAPITALIZATION RATIOS					
Common equity......................	**56.93%**	56.91%	59.99%	54.84%	53.46%
Cumulative preferred stock.........	**---**	---	---	---	3.09%
Long-term debt.....................	**43.07%**	43.09%	40.01%	45.16%	43.45%
INTEREST COVERAGES					
Before federal income taxes					
(including AFUDC)...............	**5.08X**	5.54X	5.80X	6.34X	4.43X
(excluding AFUDC)...............	**5.07X**	5.50X	5.79X	6.32X	4.42X
After federal income taxes					
(including AFUDC)...............	**3.60X**	3.91X	3.98X	4.21X	3.14X
(excluding AFUDC)...............	**3.58X**	3.86X	3.96X	4.19X	3.13X

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

Management's Discussion and Analysis.

Introduction

Oklahoma Gas and Electric Company (the "Company") generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas and is subject to the jurisdiction of the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). The Company is a wholly-owned subsidiary of OGE Energy Corp. ("Energy Corp.") which 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 owns and operates eight generating stations with a total capability of 5,732 megawatts. The Company 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. The Company 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 Company 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 the Company. 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 "The Company - Regulation and Rates - State Restructuring Initiatives" and Note 9 of Notes to Financial Statements for further discussion of these developments.

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, 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.

2002 Outlook

In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of the Company. The Company's rates had last been formally reviewed in 1995. In the filing, the OCC requested that the Company 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, 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 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 Company's 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. It has been 16 years since the Company requested a rate increase. A final order in this 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 financial position or results of operation. See "The Company - Regulation and Rates - Recent Regulatory Matters" and Note 9 of Notes to Financial Statements for further discussion of these developments.

During 2002, the Company expects 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 Generation Efficiency Performance Rider ("GEP Rider").

During 2002 and without regard to the ice storm detailed below, the Company expects 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 the Company's service territory and 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 transmission and distribution infrastructure will be capitalized as part of 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 estimate for 2002 does not include any of the costs associated with the ice storm.

Results of Operations

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

				Percent Change From Prior Year	
(thousands except per share amounts)	**2001**	2000	1999	2001	2000
Operating income	**$ 236,640**	$ 271,138	$ 269,564	(12.7)	0.6
Earnings before interest and taxes	**$ 234,177**	$ 268,393	$ 268,235	(12.7)	---
Earnings available for common stock	**$ 121,206**	$ 142,392	$ 139,041	(14.9)	2.4
Average shares outstanding	**40,379**	40,379	40,379	---	---
Dividends paid per share	**$ 2.57**	$ 2.56	$ 2.56	---	---

In reviewing its operating results, the Company believes that it is appropriate to focus on operating income and earnings before interest and taxes ("EBIT") as reported on its Statements of Income. Operating income for 2001 was $236.6 million compared to $271.1 million in 2000 and $269.6 in 1999. EBIT was $234.2 million, $268.4 million and $268.2 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.

(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

The Company's EBIT decreased approximately $34.2 million in 2001 compared to 2000. The decrease in EBIT was primarily attributable to lower kilowatt-hour sales to the Company's customers ("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. The Company's 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 the Company 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 Acquisition Premium Credit Rider ("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 9 of Notes to 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 the Company consists of cost of fuel used in electric generation and purchased power. The Company'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 the Company and its customers. In 2001, the Company'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.

The Company'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 the Company 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 the Company's 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 the Company pays to its affiliate Enogex Inc. ("Enogex"), which the Company seeks to recover through the fuel adjustment clause or other tariffs. See Note 9 of Notes to Financial Statements.

Other operating expenses include operating and maintenance expense, depreciation and amortization, and taxes other than income. The Company'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 this increase. 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 the Company 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.

The Company's EBIT increased approximately $158,000 in 2000 compared to 1999. The increase in the Company'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, the Company’s gross margin increased approximately $14.4 million or 2.0 percent over the 1999 level, primarily attributable to warmer weather in the third quarter and colder weather in the fourth quarter in the Company’s 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, the Company’s gross margin was 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. The Company’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 the Company 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.

The Company'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.

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
Construction expenditures including AFUDC..................	**$ 132.3**	$ 221.0	$ 113.0	$ 116.0	N/A
Maturities of long-term debt...........................	**---**	---	---	---	705.4
Total capital requirements....................	**132.3**	221.0	113.0	116.0	705.4
Operating lease obligations............................	**13.5**	14.5	14.5	14.5	121.8
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...............	**479.8**	571.5	425.5	408.5	1,743.2
Amounts recoverable through automatic fuel adjustment clause....................................	**(344.3)**	(349.1)	(312.5)	(292.5)	(1,032.9)
Total, net....................................	**$ 135.5**	$ 222.4	$ 113.0	$ 116.0	$ 710.3

N/A - not applicable

In January 2002, a significant ice storm hit the Company's service territory and inflicted major damage to the transmission and distribution infrastructure. Total expenditures are currently estimated at $136 million. The Company's 2002 construction expenditures in the above chart include the costs for restoration of the transmission and distribution infrastructure. 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. The Company intends to pursue a plan with the OCC to seek recovery of this cost in future rates.

During 1996, the Company 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, Energy Corp. 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 8 of Notes to Financial Statements for a more detailed discussion of these matters.

The Company's primary needs for capital are related to replacing or expanding existing facilities. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings from Energy Corp. and permanent financing. The Company had no short-term debt outstanding at December 31, 2001.

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 the Company's customers through automatic fuel adjustment clauses. Accordingly, while the cost of railcar operating leases and the vast majority of unconditional purchase obligations of the Company 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 the Company pays to its affiliate Enogex, which the Company seeks to recover through the fuel adjustment clause or other tariffs. See Note 9 of Notes to Financial Statements.

2001 Capital Requirements and Financing Activities

Capital requirements were $132.3 million in 2001. Approximately $3.3 million of the 2001 capital requirements were to comply with environmental regulations. This compares to capital requirements of $238.4 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 the decreases in the cost of natural gas.

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 values of effective fair value hedges are recorded in price risk management in the accompanying 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.

During March 2001, the Company 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"). This interest rate swap qualified as a fair value hedge under SFAS No. 133 and met all requirements for a determination that there was no ineffective portion as allowed under the shortcut method under SFAS No. 133. The objective of this interest rate swap 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.

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 its customers during the foreseeable future, the Company 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. The Company 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 Company's service territory in January 2002 and 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. The Company 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 $12.2 million in 2000 to approximately $32.9 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 7 of Notes to 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 $11.9 million. At December 31, 2001, the Company's projected pension benefit obligation exceeded the fair value of pension plan assets by approximately $85.6 million. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87, "Employers' Accounting for Pensions", required the recognition of an additional minimum liability in the amount of approximately $74.9 million. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2001 and is a non-cash charge and therefore excluded from the Statements of Cash Flows. The amount recorded as an intangible asset equaled the unrecognized prior service cost with the remainder recorded in Accumulated Other Comprehensive Income. The amount in Accumulated Other Comprehensive Income represents a net periodic pension cost to be recognized in the 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. The Company will continue to use short-term borrowings from Energy Corp. to meet temporary cash requirements. The Company has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time. At December 31, 2001, Energy Corp. 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, Energy Corp.'s $200 million line of credit was renewed for $195 million, with an expiration date of January 9, 2003. Energy Corp.'s short-term borrowings will consist of some combination of bank borrowings and commercial paper. Energy Corp.'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 Energy Corp. 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.

Critical Accounting Policies and Estimates

The Financial Statements and Notes to 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 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 pension plan assumptions, unbilled revenue, allowance for uncollectible accounts receivable and contingency reserves.

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 7 of Notes to 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.

The Company 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 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 the Company's future operations. The Company'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. The Company 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 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 the Company, 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. 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 the Company) 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.

The Company is a member of the Southwest Power Pool ("SPP"), the regional reliability organization for Oklahoma, Arkansas, Kansas, Louisiana, Missouri and part of Texas. The Company 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. The Company 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 the Company'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, the Company anticipates that it will join MISO. The transfer of operational control of the Company's transmission system to a FERC-approved RTO is not expected to significantly impact the Company's financial results. Yet, it is expected to increase the markets in which the Company 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, the Company 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 the Company'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 the Company's 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 9 of Notes to Financial Statements for a discussion of the following recent regulatory matters:

- On June 18, 2001, the OCC Staff (the “Staff”) approved a stipulation that the Company 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 the Company.
- On January 28, 2002, the Company, 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's current market risk exposure relates primarily to changes in interest rates.

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 Company has no long-term debt maturing until 2005. 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 discussion of the Company's interest rate swap agreement.

(dollars in millions)	2005	Thereafter	Total	2001 Year-end Fair Value
Fixed rate debt:				
Principal amount.........	$ 110.0	$ 350.0	$ 460.0	$ 463.8
Weighted-average interest rate..........	7.125%	6.55%	6.69%	---
Variable-rate debt:				
Principal amount.........	---	$ 243.0	$ 243.0	$ 243.0
Weighted-average interest rate..........	---	4.11%	4.11%	---

Contingencies

The Company is defending various claims and legal actions, including environmental actions, which are common to its operations. The Company 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 8 of Notes to Financial Statements.

Besides the various existing contingencies herein described, and those described in Note 8 of Notes to 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.

BALANCE SHEETS

December 31 *(dollars in thousands)*	**2001**	2000	1999
ASSETS			
CURRENT ASSETS:			
Cash and cash equivalents	**$ 380**	$ 422	$ 1,779
Accounts receivable - customers, less reserve of $6,174, $3,672 and $3,405, respectively	**98,342**	130,920	96,212
Accrued unbilled revenues	**35,600**	49,000	40,200
Accounts receivable - other	**12,073**	14,092	8,074
Fuel inventories, at LIFO cost	**54,882**	75,515	75,465
Materials and supplies, at average cost	**32,640**	32,796	30,311
Prepayments and other	**35,480**	38,521	3,100
Accumulated deferred tax assets	**7,493**	8,454	7,681
Total current assets	**276,890**	349,720	262,822
OTHER PROPERTY AND INVESTMENTS, at cost	**15,500**	15,396	12,731
PROPERTY, PLANT AND EQUIPMENT:			
In service	**3,961,652**	3,867,886	3,747,690
Construction work in progress	**22,497**	14,889	15,575
Total property, plant and equipment	**3,984,149**	3,882,775	3,763,265
Less accumulated depreciation	**1,978,872**	1,897,696	1,810,898
Net property, plant and equipment	**2,005,277**	1,985,079	1,952,367
DEFERRED CHARGES:			
Advance payments for gas	**8,500**	12,500	11,800
Income taxes recoverable through future rates	**37,615**	38,654	39,692
Intangible asset - unamortized prior service cost	**42,435**	---	---
Prepaid benefit obligation	**11,850**	---	---
Other	**36,278**	36,100	41,248
Total deferred charges	**136,678**	87,254	92,740
TOTAL ASSETS	**$ 2,434,345**	$ 2,437,449	$ 2,320,660

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

BALANCE SHEETS (Continued)

December 31 *(dollars in thousands)*	**2001**	2000	1999
LIABILITIES AND STOCKHOLDERS' EQUITY			
CURRENT LIABILITIES:			
Accounts payable - affiliates	**$ 25,867**	$ 90,474	$ 75,674
Accounts payable - other	**63,577**	107,416	36,231
Customers' deposits	**28,423**	22,645	22,137
Accrued taxes	**20,255**	19,951	19,545
Accrued interest	**14,437**	14,535	14,573
Accrued vacation	**11,796**	11,386	11,437
Provision for payments of take or pay gas	**30,800**	2,500	3,100
Fuel clause over recoveries	**23,358**	---	1,573
Long-term debt due within one year	**---**	---	110,000
Other	**6,338**	7,363	4,783
Total current liabilities	**224,851**	276,270	299,053
LONG-TERM DEBT	**700,379**	702,582	593,045
DEFERRED CREDITS AND OTHER LIABILITIES:			
Accrued pension and benefit obligations	**80,850**	11,277	14,886
Accumulated deferred income taxes	**438,972**	449,420	450,028
Accumulated deferred investment tax credits	**52,279**	57,429	62,578
Price risk management	**2,412**	---	---
Other	**9,000**	12,500	11,933
Total deferred credits and other liabilities	**583,513**	530,626	539,425

STOCKHOLDERS' EQUITY:

Common stockholders' equity	**512,446**	512,446	512,446
Retained earnings	**433,094**	415,525	376,691
Accumulated other comprehensive income (loss), net of tax	**(19,938)**	---	---
Total stockholders' equity	**925,602**	927,971	889,137
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 2,434,345**	$ 2,437,449	$ 2,320,660

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

STATEMENTS OF CAPITALIZATION

December 31 *(dollars in thousands)*		**2001**	2000	1999
COMMON STOCK AND RETAINED EARNINGS:				
Common stock, par value $2.50 per share, authorized 100,000,000 shares; and outstanding 40,378,745 shares		**$ 100,947**	$ 100,947	$ 100,947
Premium on capital stock		**411,499**	411,499	441,499
Retained earnings		**433,094**	415,525	376,691
Accumulated other comprehensive income (loss), net of tax		**(19,938)**	---	---
Total common stock and retained earnings		**925,602**	927,971	889,137
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)	(2,355)
Total long-term debt		**700,379**	702,582	703,045
Less long-term debt due within one year		**---**	---	110,000
Total long-term debt (excluding long-term debt due within one year)		**700,379**	702,582	593,045
Total Capitalization		**$ 1,625,981**	$ 1,630,553	$ 1,482,182

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

STATEMENTS OF INCOME

Year ended December 31 *(dollars in thousands except per share data)*	**2001**	2000	1999
OPERATING REVENUES	**$ 1,456,802**	$ 1,453,585	$ 1,286,844
COST OF GOODS SOLD	**766,491**	752,377	600,017
Gross margin on revenues	**690,311**	701,208	686,827
Other operation and maintenance	**287,265**	267,353	253,312
Depreciation and amortization	**119,794**	117,257	119,059
Taxes other than income	**46,612**	45,460	44,892
OPERATING INCOME	**236,640**	271,138	269,564
OTHER EXPENSES,NET	**(2,463)**	(2,745)	(1,329)
EARNINGS BEFORE INTEREST AND TAXES	**234,177**	268,393	268,235
INTEREST INCOME (EXPENSES):			
Interest income	**2,443**	1,121	1,710
Interest on long-term debt	**(42,256)**	(45,858)	(44,813)
Allowance for borrowed funds used during construction	**707**	2,229	719
Other interest charges	**(4,438)**	(3,151)	(1,845)
Net interest income (expenses)	**(43,544)**	(45,659)	(44,229)
INCOME BEFORE TAXES	**190,633**	222,734	224,006
INCOME TAX EXPENSE	**69,427**	80,342	84,965
NET INCOME	**$ 121,206**	$ 142,392	$ 139,041
AVERAGE COMMON SHARES OUTSTANDING (thousands)	**40,379**	40,379	40,379
EARNINGS PER AVERAGE COMMON SHARE	**$ 3.00**	$ 3.53	$ 3.44
AVERAGE COMMON SHARES OUTSTANDING ASSUMING DILUTION (thousands)	**40,379**	40,379	40,379
EARNINGS PER AVERAGE COMMON SHARE ASSUMING DILUTION	**$ 3.00**	$ 3.53	$ 3.44
DIVIDENDS DECLARED PER SHARE	**$ 2.57**	$ 2.56	$ 2.56

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

STATEMENTS OF RETAINED EARNINGS

Year ended December 31 *(dollars in thousands)*	**2001**	2000	1999
BALANCE AT BEGINNING OF PERIOD	**$ 415,525**	$ 376,691	$ 341,125
ADD - net income	**121,206**	142,392	139,041
Total	**536,731**	519,083	480,166
DEDUCT:			
Cash dividends declared on common stock	**103,637**	103,558	103,475
Total	**103,637**	103,558	103,475
BALANCE AT END OF PERIOD	**$ 433,094**	$ 415,525	$ 376,691

STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(dollars in thousands)*	**2001**	2000	1999
Net Income	**$ 121,206**	$ 142,392	$ 139,041
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment [$32,525 pretax]	**(19,938)**	---	---
Total other comprehensive income (loss), net of tax	**(19,938)**	---	---
Total comprehensive income	**$ 101,268**	$ 142,392	$ 139,041

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

STATEMENTS OF CASH FLOWS

Year ended December 31 *(dollars in thousands)*	**2001**	2000	1999
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	**$ 121,206**	$ 142,392	$ 139,041
Adjustments to Reconcile Net Income to Net Cash Provided from Operating Activities:			
Depreciation and amortization	**119,794**	117,257	119,059
Deferred income taxes and investment tax credits, net	**(195)**	(4,677)	(16,945)
Change in Certain Current Assets and Liabilities:			
Accounts receivable - customers	**32,578**	(34,708)	(4,778)
Accrued unbilled revenues	**13,400**	(8,800)	(17,700)
Fuel, materials and supplies inventories	**20,789**	(2,535)	(32,801)
Accumulated deferred tax assets	**961**	(773)	(792)
Other current assets	**5,060**	(41,439)	25,190
Accounts payable	**(69,247)**	102,248	(56,137)
Accrued taxes	**304**	406	613
Accrued interest	**(98)**	(38)	(1,358)
Other current liabilities	**56,821**	865	(4,696)
Other operating activities	**(26,279)**	(23,323)	2,047
Net cash provided from operating activities	**275,094**	246,875	150,743
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	**(132,300)**	(128,410)	(101,263)
Net cash used in investing activities	**(132,300)**	(128,410)	(101,263)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Retirement of long-term debt	**---**	(110,000)	---
Proceeds from long-term debt	**---**	110,000	---
Increase (decrease) in short-term debt, net	**(39,199)**	(16,264)	55,462
Cash dividends declared on common stock	**(103,637)**	(103,558)	(103,475)
Net cash used in financing activities	**(142,836)**	(119,822)	(48,013)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**(42)**	(1,357)	1,467
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**422**	1,779	312
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 380**	$ 422	$ 1,779
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
CASH PAID DURING THE PERIOD FOR:			
Interest (net of amount capitalized $707, $2,229 and $719)	**$ 37,056**	$ 47,162	$ 46,257
Income taxes	**$ 985**	$ 99,100	$ 51,557
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Interest rate swap	**$ 2,412**	$ ---	$ ---
Change in fair-value of long-term debt	**$ (2,412)**	$ ---	$ ---

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

NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

Oklahoma Gas and Electric Company (the "Company") is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity to retail and wholesale customers in Oklahoma and western Arkansas. The Company is a wholly-owned subsidiary of OGE Energy Corp. ("Energy Corp.") which 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 owns and operates eight generating stations with a total capability of 5,732 megawatts. The Company was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in the State of Oklahoma.

Accounting Records

The accounting records of the Company 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, the Company, 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 deferred charges - other, on the Balance Sheets included the following, as of December 31:

Deferred Charges - Other

(dollars in thousands)	**2001**	2000	1999
Regulated Deferred Charges:			
Unamortized debt expense..............................	**$ 5,203**	$ 5,565	$ 5,196
Unamortized loss on reacquired debt...................	**24,473**	25,644	27,281
Miscellaneous...	**432**	475	1,317
Total regulated deferred charges..................	**30,108**	31,684	33,794
Miscellaneous Non-Regulated Deferred Charges............	**6,170**	4,416	7,454
Total Other Deferred Charges............................	**$ 36,278**	$ 36,100	$ 41,248

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**	475	1,317
Total Regulatory Assets........................	**98,250**	109,736	122,486
Regulatory Liabilities:			
Income taxes refundable to customers................	**(35,730)**	(44,963)	(54,196)
Net Regulatory Assets..................................	**$ 62,520**	$ 64,773	$ 68,290

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 values of effective fair value hedges are recorded in price risk management in the accompanying 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.

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 and distribution 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 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 financial position or results of operation.

Use of Estimates

In preparing the 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 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. Replacement 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 Statements of Income as 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.

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 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 Balance Sheets not otherwise discussed in these notes approximate fair value.

Cash and Cash Equivalents

For purposes of these statements, the Company considers all highly liquid debt instruments purchased with a 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 $20.2 million, $23.2 million and zero at December 31, 2001, 2000 and 1999, respectively, and are classified as accounts payable in the accompanying Balance Sheets. Sufficient funds were available to fund these outstanding checks when they were presented for payment.

Heat Pump Loans

The Company has a heat pump loan program, whereby, qualifying customers may obtain a loan from the Company 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 percent 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 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 Balance Sheets. The Company sold approximately $12.7 million of its heat pump loans in 1999.

Revenue Recognition

The Company's customers are billed monthly on a cycle basis. The Company accrues estimated revenues for services provided but not yet billed, as the cost of providing service is recognized as incurred.

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 the Company'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 Credit 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 the APC Rider is to credit the Oklahoma retail customers for the completion of the OCC authorized recovery of the premium paid by the Company when it acquired Enogex Inc. ("Enogex") in 1986. The GTAC Rider and the APC Rider are both applicable to each Oklahoma retail rate schedule to which the Company's fuel cost adjustment clause applies.

Fuel Inventories

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. These inventories are accounted for under the last-in, first-out ("LIFO") cost method. The estimated replacement cost of fuel inventories was higher than the stated LIFO cost by approximately $13.0 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.

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.

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 the Company has been designated as one of several potentially responsible parties, the amount accrued represents the Company's estimated share of the cost.

Related Party Transactions

Energy Corp. allocated operating costs to the Company of approximately $85.5 million, $84.8 million and $81.9 million during 2001, 2000 and 1999, respectively. Energy Corp. 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.

In 2001, 2000 and 1999, the Company paid its affiliate Enogex approximately $36.3 million, $37.4 million and $41.5 million, respectively, for transporting gas to the Company's gas-fired generating stations. In 1997, the Company began purchasing a significant portion of its natural gas generation fuel supply through a subsidiary of Enogex. These purchases are priced based on a market basket of posted prices within the region and are priced similar to purchases, which had previously been made directly from unaffiliated sources. Approximately $111,000, $5.5 million and $6.6 million was recorded at December 31, 2001, 2000 and 1999, respectively, and is included in accounts payable - affiliates in the accompanying Balance Sheets for these activities.

Reclassifications

Certain amounts have been reclassified on the 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	**$ 59,758**	$ 71,056	$ 86,749
State	**9,872**	14,591	15,016
Total Provision For Current Income Taxes	**69,630**	85,647	101,765
Provisions (Benefit) For Deferred Income Taxes, net:			
Federal			
Depreciation	**(1,435)**	10,452	(9,028)
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)	---
Casualty losses	**3,507**	(5,439)	5,167
Contributions in aid of construction	**(4,270)**	(2,689)	---
Company restructuring	**90**	67	100
Pension expense	**4,735**	662	(2,486)
Bond redemption-unamortized costs	**(353)**	(1,064)	249
Other	**(267)**	(506)	(6,297)
State	**1,076**	(552)	(1,809)
Total Provision(Benefit) For Deferred Income Taxes, net	**4,956**	472	(11,796)
Deferred Investment Tax Credits, net	**(5,150)**	(5,150)	(5,150)
Income Taxes Relating to Other Income and Deductions	**(9)**	(627)	146
Total Income Tax Expense	**$ 69,427**	$ 80,342	$ 84,965
Pretax Income	**$ 190,633**	$ 222,734	$ 224,006

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	**3.7**	4.1	3.8
Tax credits, net	**(2.7)**	(2.3)	(2.3)
Other, net	**0.4**	(0.7)	1.4
Effective income tax rate as reported	**36.4%**	36.1%	37.9%

The Company is a member of an affiliated group that files consolidated income tax returns. Income taxes are allocated to each company in the affiliated group 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 the Company. The components of Accumulated Deferred Income Taxes are as follows:

Year Ended December 31 *(dollars in thousands)*	**2001**	2000	1999
Current Accumulated Deferred Tax Assets:			
Accrued vacation	**$ 4,011**	$ 4,105	$ 5,005
Uncollectible accounts	**2,390**	3,090	1,428
Capitalization of indirect costs	**258**	318	249
RAR interest	**774**	774	774
Provision for Worker's Compensation claims	**60**	167	225
Total Current Accumulated Deferred Tax Assets	**$ 7,493**	$ 8,454	$ 7,681
Non-Current Accumulated Deferred Tax Liabilities:			
Accelerated depreciation and other property-related differences	**$ 408,229**	$ 416,558	$ 415,213
Allowance for funds used during construction	**37,466**	34,093	37,152
Income taxes recoverable through future rates	**28,389**	32,365	36,335
Total Non-Current Accumulated Deferred Tax Liabilities	**474,084**	483,016	488,700
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	**(124)**	548	(290)
Company pension plan	**(12,620)**	(6,125)	(5,892)
Bond redemption-unamortized costs	**8,549**	8,964	9,640
Other	**(1,495)**	(1,191)	(1,026)
Total Non-Current Accumulated Deferred Tax Assets	**(35,112)**	(33,596)	(38,672)
Net Non-Current Accumulated Deferred Income Tax Liabilities	**$ 438,972**	$ 449,420	$ 450,028

3. Common Stock and Retained Earnings

There were no new shares of common stock issued during 2001, 2000 or 1999.

4. Cumulative Preferred Stock

In 1998, all outstanding shares of the Company's Cumulative Preferred Stock were redeemed.

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

5. Long-Term Debt

During March 2001, the Company 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"). This interest rate swap qualified as a fair value hedge under SFAS No. 133 and met all requirements for a determination that there was no ineffective portion as allowed under the shortcut method under SFAS No. 133. The objective of this interest rate swap was to hedge the fair value of the underlying debt and to raise the percentage of total corporate floating rate long-term debt to reflect a level more in line with industry standard. At December 31, 2001, the change in fair value pursuant to the interest rate swap is approximately $2.4 million and is included in non-current price risk management in the accompanying Balance Sheets. a corresponding decrease of $2.4 million is reflected in the Company's long-term debt at December 31, 2001, as the fair value hedge has no ineffectiveness as of December 31, 2001.

On October 15, 2000, a $110 million series of the Company's 6.25 percent Senior Notes matured. The Company temporarily funded this transaction through short-term borrowings from Energy Corp. On October 23, 2000, the Company 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 Energy Corp.

Maturities of long-term debt during the next five years consist of $110 million in 2005.

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 Balance Sheets.

6. Short-Term Debt

The Company uses short-term borrowings from Energy Corp. to meet its temporary cash requirements. The Company has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time. At December 31, 2001, Energy Corp. 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, Energy Corp.'s $200 million line of credit was renewed for $195 million, with an expiration date of January 9, 2003. Energy Corp.'s short-term borrowings will consist of some combination of bank borrowings and commercial paper. Energy Corp.'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 Energy Corp. 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 did not have any short-term debt outstanding at December 31, 2001. The Company had $39.2 million and $55.5 million in short-term debt outstanding at December 31, 2000 and 1999, respectively.

7. Pension and Postemployment 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 $32.9 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 $11.9 million. At December 31, 2001, the

Company's projected pension benefit obligation exceeded the fair value of pension plan assets by approximately $85.6 million. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87, "Employers' Accounting for Pensions", required the recognition of an additional minimum liability in the amount of approximately $74.9 million. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2001 and is a non-cash charge and therefore excluded from the Statements of Cash Flows. The amount recorded as an intangible asset equaled the unrecognized prior service cost with the remainder recorded in Accumulated Other Comprehensive Income. The amount in Accumulated Other Comprehensive Income represents a net periodic pension cost to be recognized in the Statements of Income in future periods.

The plan's assets consist primarily of U. S. Government securities, listed common stocks 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 postretirement 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

postretirement 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. The Company 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 funded status of the plans and the amounts included in the Company's Balance Sheets follows:

Projected Benefit Obligations:

	Pension Plan			Postretirement Benefit Plans		
(dollars in thousands)	**2001**	2000	1999	**2001**	2000	1999
Beginning obligations......	**$(342,045)**	$(266,674)	$(303,925)	**$ (90,048)**	$ (74,409)	$ (81,495)
Service cost..............	**(8,442)**	(7,402)	(6,018)	**(1,447)**	(1,452)	(2,007)
Interest cost.............	**(25,818)**	(24,068)	(19,095)	**(7,433)**	(6,417)	(5,419)
Participant contributions..	**---**	---	---	**(1,217)**	(1,093)	(1,142)
Plan changes..............	**---**	(17,061)	---	**---**	(14,011)	---
Actuarial gains (losses)...	**(4,954)**	(63,247)	44,347	**(16,585)**	(1,503)	6,692
Benefits paid.............	**34,913**	35,745	17,309	**9,757**	8,837	8,962
Expenses..................	**1,173**	662	708	**---**	---	---
Ending obligations.........	**$(345,173)**	$(342,045)	$(266,674)	**$(106,973)**	$ (90,048)	$ (74,409)

Fair Value of Plans' Assets:

	Pension Plan			Postretirement Benefit Plans		
(dollars in thousands)	**2001**	2000	1999	**2001**	2000	1999
Beginning fair value...........	**$ 254,113**	$ 270,071	$ 265,649	**$ 53,768**	$ 53,727	$ 50,588
Actual return on plans' assets..	**8,600**	8,272	19,582	**(2,650)**	41	3,139
Employer contributions..........	**32,926**	12,177	2,857	**8,539**	6,184	6,307
Participants' contributions.....	**---**	---	---	**1,217**	943	980
Benefits paid...................	**(34,913)**	(35,745)	(17,309)	**(9,757)**	(7,127)	(7,287)
Expenses........................	**(1,173)**	(662)	(708)	**---**	---	---
Ending fair value..............	**$ 259,553**	$ 254,113	$ 270,071	**$ 51,117**	$ 53,768	$ 53,727

Net Periodic Benefit Cost:

	Pension Plan			Postretirement Benefit Plans		
(dollars in thousands)	**2001**	2000	1999	**2001**	2000	1999
Service cost....................	**$ 8,442**	$ 7,402	$ 6,018	**$ 1,447**	$ 1,452	$ 2,007
Interest cost...................	**25,818**	24,068	19,095	**7,433**	6,417	5,419
Return on plan assets...........	**(17,718)**	(20,605)	(23,809)	**(5,184)**	(4,825)	(3,844)
Amortization of transition obligation....................	**(1,173)**	(1,173)	(1,173)	**2,541**	2,541	2,541
Amortization of net (gain) loss.	**405**	(350)	---	**(651)**	(1,514)	(1,196)
Net amount capitalized or deferred......................	**(3,419)**	(2,245)	(880)	**---**	---	(1,086)
Amortization of unrecognized prior service cost............	**4,740**	4,128	2,906	**1,530**	1,021	---
Net periodic benefit costs......	**$ 17,095**	$ 11,225	$ 2,157	**$ 7,116**	$ 5,092	$ 3,841

Funded Status of Plans:

	Pension Plan			Postretirement Benefit Plans		
(dollars in thousands)	**2001**	2000	1999	**2001**	2000	1999
Funded status of the plans......	**$ (85,620)**	$ (87,932)	$ 3,397	**$ (55,856)**	$ (36,280)	$ (20,682)
Unrecognized net (gain) loss....	**55,035**	37,950	(40,225)	**10,550**	(14,520)	(22,321)
Unrecognized prior service cost..........................	**42,435**	47,175	34,242	**11,462**	12,991	---
Unrecognized transition obligation....................	**---**	(1,174)	(2,347)	**27,954**	30,495	33,037
Net amount recognized..........	**$ 11,850**	$ (3,981)	$ (4,933)	**$ (5,890)**	$ (7,314)	$ (9,966)

Amounts recognized in the Balance Sheets consist of:

	Pension Plan		
(dollars in thousands)	**2001**	2000	1999
Prepaid benefit cost............	**$ 11,850**	N/A	N/A
Accrued benefit liability........	**(74,960)**	N/A	N/A
Intangible asset.................	**42,435**	N/A	N/A
Deferred tax asset...............	**12,587**	N/A	N/A
Accumulated other comprehensive income...........	**19,938**	N/A	N/A
Net amount recognized...........	**$ 11,850**	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 increases of approximately $1.0 million, $0.9 million and $0.8 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 $0.8 million, $0.7 million and $0.7 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 increases of approximately $11.8 million, $9.4 million and $6.1 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 $9.8 million, $7.8 million and $5.2 million at December 31, 2001, 2000 and 1999, respectively.

8. Commitments and Contingencies

The Company 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 $221.0 million.

The Company acquires some of its natural gas for boiler fuel under a wellhead contract that contains provisions allowing the owners 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, the Company held non-cancelable operating leases covering 1,481 coal hopper railcars. Rental payments are charged to fuel expense and recovered through the Company'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.

The Company 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.

The Company 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 the Company to lower fuel costs by base loading coal generation, a less costly fuel supply. During 1996, the Company completed negotiations and contracted with COOG for gas storage service. Pursuant to the contract, COOG reimbursed the Company for all outstanding cash advances and interest amounting to approximately $46.8 million. The Company also entered into a bridge financing agreement as guarantor for COOG. In 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, Energy Corp. 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.

The Company 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 the Company to purchase power generated in a manufacturing process from a qualified cogeneration facility ("QF"). The rate for such power to be paid by the Company was approved by the OCC. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by the Company; the other is a capacity charge, which the Company must pay the QF for having

the capacity available. However, if no electrical power is made available to the Company for a period of time (generally three months), the Company'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, the Company 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 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, the Company became subject to more stringent sulfur dioxide emissions. These lower limits had no significant financial impact due to the Company's earlier decision to burn low sulfur coal. In 2001, the Company's sulfur dioxide emissions were well below the allowable limits. With respect to nitrogen oxides ("NOx"), the Company continues to meet the current emission standard. However, further reductions in NOx 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 NOx 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, it 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, the Company had submitted all required permit applications. As of December 31, 2001, the Company had received Title V permits for all but one of its generating stations. Since the Company submitted all of 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, the 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 the Company'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. 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 financial position or results of operations.

9. 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 the Company. The review resulted in an aggregate score of 17 for the Company, with only one indicator "Time since last formal rate review", achieving a rating of three. The Company'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 the Company.

In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of the Company. In the filing, the Staff requested that the Company 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, the Company, citing the need for investment in security and system reliability, filed a notice with the OCC of its intent to seek an increase in the Company's electric rates. On January 28, 2002, the Company filed testimony with the OCC supporting the Company's request for a $22 million annual rate increase. If granted, the increase would be the first for the Company since 1985. Over the past 16 years, the Company has had rate reductions of more than $142 million. Attempting to make security investments at the proper level, the Company 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 the Company 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 the Company was to invest in increased

security. The additional $12 million is for investment in increased system reliability and for increased utility costs. The Company 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, the Company has experienced an overall increase in operating expenses. As part of it's filing, the Company 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 the Company 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 the Company's offer to not seek a rate increase for three years. A final order in the Company's rate case is not expected before summer 2002.

As previously reported, certain aspects of the Company's electric rates recently have been addressed by the OCC. In March 2000, the OCC approved, and the Company implemented, the APC Rider reflecting the completion of the recovery of the amortization premium paid by the Company 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 the Company from its Oklahoma customers in current rates.

In June 2000, the OCC approved modifications to the Company's Generation Efficiency Performance Rider ("GEP Rider"). The GEP Rider was established initially in 1997 in connection with the Company's last general rate review and was intended to encourage the Company to lower its fuel costs by: (i) allowing the Company 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 the Company could recover under the GEP Rider by: (i) changing the Company'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 the Company's costs exceed the new peer group by changing the percentage above which the Company 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 the Company'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 the Company or penalties charged to the Company. 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 the Company's gas transportation needs following which the Company's affiliate, Enogex, contracted to provide gas transportation service to all of the Company's generation plants. In the 1997 Order, the OCC approved a stipulation wherein the Company 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 the Company 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

the Company 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, the Company 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, the Company stated that Enogex had submitted the only viable bid ($33.4 million per year) for gas transportation to the Company's six gas-fired power plants that were the subject of the competitive bid. As part of its application to the OCC, the Company offered to discount Enogex's bid from $33.4 million annually to $25.2 million annually. The Company executed a gas transportation contract with Enogex under which Enogex continues to serve the needs of the Company's power plants at a price to be paid by the Company of $33.4 million annually and, if the Company's proposal had been approved by the OCC, the Company would have recovered a portion of such amount ($25.2 million) from its customers. The Company 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, the Company withdrew its application, which withdrawal was approved by the OCC in December 1999.

In July 2000, the Company 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 the Company'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. The Company 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 the Company to recover $25.2 million annually for the gas transportation services provided by Enogex pursuant to the competitive bid process. The Stipulation directs the Company 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 the Company'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 the Company at the direction of the OCC.

On February 13, 1998, the APSC staff filed a motion for a show cause order to review the Company'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 the Company reached a settlement for a $2.3 million annual rate reduction, which was approved by the APSC in August 1999.

10. Disclosures about Fair Value of Financial Instruments

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.

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:						
Senior Notes..........................	**$564,979**	**$571,426**	$567,182	$552,256	$457,181	$422,181
Industrial Authority Bonds............	**135,400**	**135,400**	135,400	135,400	135,400	135,400

11. Subsequent Events

In January 2002, Energy Corp.'s line of credit for $200 million was renewed for $195 million, with an expiration date of January 9, 2003.

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

In January 2002, a significant ice storm hit the Company's service territory and 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 Company's transmission and distribution infrastructure will be capitalized as part of plant. The Company believes its short-term borrowing capacity is adequate to finance the restoration of the transmission and distribution infrastructure. The area of damage is within counties that were declared a federal disaster area. The Company 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.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

ARTHUR ANDERSEN

To the Shareowner of Oklahoma Gas and Electric Company:

We have audited the accompanying balance sheets and statements of capitalization of Oklahoma Gas and Electric Company (an Oklahoma corporation) as of December 31, 2001, 2000 and 1999, and the related 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 Oklahoma Gas and Electric Company as of December 31, 2001, 2000 and 1999, and the results of its operations and its 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 Shareowner:

The management of the Company is responsible for the preparation, integrity and objectivity of the financial statements of the Company and other information included in this report. The 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 financial statements. Management believes that the system of control provides reasonable assurance that errors or irregularities that could be material to the 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 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 financial statements of the Company and to issue their report thereon.

/s/ Steven E. Moore	/s/ Al M. Strecker
Steven E. Moore, Chairman of the Board, President and Chief Executive Officer	Al M. Strecker, Executive Vice President and Chief Operating Officer
/s/ James R. Hatfield	/s/ Donald R. Rowlett
James R. Hatfield, Sr. Vice President and Chief Financial Officer	Donald R. Rowlett, Vice President and Controller

Supplementary Data

INTERIM 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**	**$ 262,344**	**$ 508,142**	**$ 359,481**	**$ 326,835**
	2000	343,687	528,993	335,573	245,332
	1999	257,616	464,982	314,102	250,144
Operating income (loss).....................	**2001**	**$ (1,022)**	**$ 172,310**	**$ 56,150**	**$ 9,202**
	2000	24,640	185,049	55,681	5,768
	1999	18,300	163,268	60,697	27,299
Net income (loss)...........................	**2001**	**$ (5,939)**	**$ 100,117**	**$ 28,025**	**$ (997)**
	2000	8,730	107,327	29,561	(3,226)
	1999	7,370	87,753	33,729	10,189
Earnings (loss) per average common share....	**2001**	**$ (0.15)**	**$ 2.48**	**$ 0.69**	**$ (0.02)**
	2000	0.22	2.66	0.73	(0.08)
	1999	0.18	2.17	0.84	0.25

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.

Under the reduced disclosure format permitted by General Instruction I(2)(c) of Form 10-K, the information otherwise required by Items 10, 11, 12 and 13 has been omitted.

PART IV

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

(a) 1. Financial Statements

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

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

Supplementary Data

- Interim Financial Information

2. Financial Statement Schedule (included in Part IV)

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
3.01	Copy of Restated Certificate of Incorporation. (Filed as Exhibit 4.01 to the Company's Registration Statement No. 33-59805, and incorporated by reference herein)
3.02	By-laws. (Filed as Exhibit 4.02 to Post-Effective Amendment No. Three to Registration Statement No. 2-94973 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 the Company'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)

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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 the Company and Atlantic Richfield Company. (Filed as Exhibit 5.19 to Registration Statement No. 2-59887 and incorporated by reference herein)

10.02 Amendment dated April 1, 1976, to Coal Supply Agreement dated March 1, 1973, between the Company and Atlantic Richfield Company, together with related correspondence. (Filed as Exhibit 5.21 to Registration Statement No. 2-59887 and incorporated by reference herein)

10.03 Second Amendment dated March 1, 1978, to Coal Supply Agreement dated March 1, 1973, between the Company and Atlantic Richfield Company. (Filed as Exhibit 5.28 to Registration Statement No. 2-62208 and incorporated by reference herein)

10.04 Amendment dated June 27, 1990, between the Company and Thunder Basin Coal Company, to Coal Supply Agreement dated March 1, 1973, between the Company and Atlantic Richfield Company. (Filed as Exhibit 10.04 to the Company's Form 10-K Report for the year ended December 31, 1994 (File No. 1-1097) and incorporated by reference herein) [Confidential Treatment has been requested for certain portions of this exhibit.]

10.05 Form of Change of Control Agreement for Officers of the Company and Energy Corp. (Filed as Exhibit 10.07 to Energy Corp.'s Form 10-K Report for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

10.06 Energy Corp. Directors' Deferred Compensation Plan. (Filed as Exhibit 10.06 to Energy Corp.'s Form 10-K Report for the year ended December 31, 1999 (File No. 1-12579) and incorporated by reference herein)

10.07 Energy Corp.'s Stock Incentive Plan. (Filed as Exhibit 10.07 to Energy Corp.'s Form 10-K Report for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)

10.08 Oklahoma Gas and Electric Company Restoration of Retirement Income Plan, as amended. (Filed as Exhibit 10.12 to Energy Corp.'s Form 10-K Report for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

10.09 Oklahoma Gas and Electric Company Supplemental Executive Retirement Plan. (Filed as Exhibit 10.15 to Energy Corp.'s Form 10-K Report for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

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

10.11 Energy Corp.'s Deferred Compensation Plan. (Filed as Exhibit 4 to Energy Corp.'s Form S-8 Registration Statement No. 333-92423 and incorporated by reference herein)

10.12 Amendment No. 3 to Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to Energy Corp.'s Form 10-K Report for the year ended December 31, 2000 (File No. 1-12519) and incorporated by reference herein)

10.13 Amendment No. 4 to Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.14 to Energy Corp.'s Form 10-K Report for the year ended December 31, 2000 (File No. 1-12519) and incorporated by reference herein)

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 Representations by Arthur Andersen LLP in connection with audit of Oklahoma Gas and Electric Company.

Executive Compensation Plans and Arrangements

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(b) Reports on Form 8-K

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

OKLAHOMA GAS AND ELECTRIC COMPANY

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	$ 2,441	$ 8,596	-	$ 7,632(1)	$ 3,405

Year Ended December 31, 2000

Reserve for Uncollectible Accounts	$ 3,405	$ 5,095	-	$ 4,828(1)	$ 3,672

Year Ended December 31, 2001

Reserve for Uncollectible Accounts	$ 3,672	$15,830	-	$13,328(1)	$ 6,174

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

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Oklahoma Gas and Electric Company:

We have audited in accordance with auditing standards generally accepted in the United States, the financial statements of Oklahoma Gas and Electric Company (an Oklahoma Corporation) 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 67, 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.

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

10.11 Energy Corp.'s Deferred Compensation Plan. (Filed as Exhibit 4 to the Company's Form S-8 Registration Statement No. 333-92423 and incorporated by reference herein)

10.12 Amendment No. 3 to Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to Energy Corp.'s Form 10-K Report for the year ended December 31, 2000 (File No. 1-12519) and incorporated by reference herein)

10.13 Amendment No. 4 to Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.14 to Energy Corp.'s Form 10-K Report for the year ended December 31, 2000 (File No. 1-12519) and incorporated by reference herein)

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 Representations by Arthur Andersen LLP in connection with audit of Oklahoma Gas and Electric Company

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 Oklahoma Gas and Electric Company Form 10-K for the year ended December 31, 2001, into the previously filed Form S-3 Registration Statement No. 333-46169, Form S-3 Registration Statement No. 333-21059 and Form S-4 Registration Statement No. 33-61699.

/s/ Arthur Andersen LLP
Arthur Andersen LLP

Oklahoma City, Oklahoma,
March 27, 2002

Exhibit 24.01

POWER OF ATTORNEY

WHEREAS, OKLAHOMA GAS AND ELECTRIC COMPANY, 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 OKLAHOMA GAS AND ELECTRIC COMPANY, 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

Oklahoma Gas and Electric Company 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 Oklahoma Gas and Electric Company (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 defaults;
- 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 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 8 of Notes to 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