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, 2003

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ____ No X

As of June 30, 2003, the last business day of the registrant's most recently completed second fiscal quarter, 40,378,745 shares of common stock, par value $2.50 per share, were outstanding, all of which were held by OGE Energy Corp.

As of January 31, 2004, 40,378,745 shares of common stock, par value $2.50 per share, were outstanding, 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

OKLAHOMA GAS AND ELECTRIC COMPANY

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2003

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PART I

Item 1. Business.

THE COMPANY

Oklahoma Gas and Electric Company (the "Company") generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas and is subject to regulation by 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 was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. The Company sold its retail gas business in 1928 and is no longer engaged in the gas distribution business. The Company's principal executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone (405) 553-3000.

The Company has been and will continue to be affected by competitive changes to the utility industry. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although it appears unlikely in the near future that changes will occur to retail regulation in the states served by the Company due to the significant problems faced by California in its electric deregulation efforts and other factors, significant changes are possible, which could significantly change the manner in which the Company conducts its business. These developments at the federal and state levels are described in more detail below under "Regulation and Rates – State Restructuring Initiatives and National Energy Legislation."

On October 11, 2002, the Company, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to a settlement (the "Settlement Agreement") of the Company's rate case. The terms of the settlement are described below in "Regulation and Rates – 2002 Settlement Agreement."

Company Strategy

In early 2002, Energy Corp. completed a review of its business strategy that was largely driven by the anticipated deregulation of the retail electric markets in Oklahoma and Arkansas. Due to a variety of factors, including the current efforts to repeal the Oklahoma Electric Restructuring Act of 1997 and the recent repeal of the Restructuring Law in Arkansas, Energy Corp. does not anticipate that deregulation of the electricity markets in Oklahoma or Arkansas will occur in the foreseeable future. The strategic direction of Energy Corp. has been revised to reflect these developments. As a result, Energy Corp. expects potentially slower earnings growth than associated with deregulation but with less variability of those earnings.

Energy Corp.'s revised business strategy will utilize the diversified asset position of the Company and Energy Corp.'s wholly-owned natural gas pipeline subsidiary, Enogex Inc. and subsidiaries ("Enogex"), to provide energy products and services to customers primarily in the south central United States. Energy Corp. will focus on those products and services with limited or manageable commodity exposure. Energy Corp. intends for the Company to continue as a vertically integrated utility engaged in the generation, transmission and the distribution of electricity and to represent over time approximately 70 percent of Energy Corp.'s consolidated assets. The remainder of Energy Corp.'s consolidated assets will be in Enogex's businesses. At December 31, 2003, the Company and Enogex represented approximately 61 percent and 35 percent, respectively, of Energy Corp.'s consolidated assets. The remaining four percent of Energy Corp.'s consolidated assets were primarily at the holding company. In addition to the incremental growth opportunities that Enogex provides, Energy Corp. believes that Enogex's risk management capabilities, commercial skills and market information provide value to all of Energy Corp.'s businesses. Federal regulation in regard to the operations of the wholesale power market may change with the evolving policy at the FERC. In addition, Oklahoma and Arkansas legislatures and utility commissions may propose changes from time to time that could subject utilities to market risk. Accordingly, the Company is applying risk management practices to all of its operations in an effort to mitigate the potential adverse effect of any future regulatory changes. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Company Strategy" for a further discussion.

General

The Company furnishes retail electric service in 270 communities and their contiguous rural and suburban areas. During 2003, five other communities and three rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from the Company for resale. The service area, with an estimated population of 1.9 million, covers approximately 30,000 square miles in Oklahoma and western Arkansas; including Oklahoma City, the largest city in Oklahoma, and Fort Smith, Arkansas. Of the 270 communities served, 244 are located in Oklahoma and 26 in Arkansas. Approximately 89 percent of total electric operating revenues for the year ended December 31, 2003, 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 during 2003 was approximately 5,977 MWs on August 21, 2003. The Company's load responsibility peak demand was approximately 5,657 MWs on August 21, 2003, resulting in a capacity margin of approximately 14.0 percent. As reflected in the table on page 3 and in the operating statistics on page 4, there were approximately 25.1 million megawatt-hour ("MWH") sales in 2003 as compared to approximately 24.9 million in 2002 and 2001. MWH sales to the Company's customers ("system sales") increased approximately 1.6 percent in 2003, due to increased usage related to customer growth in the Company's service territory partially offset by milder weather during 2003. Sales to other utilities and power marketers ("off-system sales") decreased approximately 67.0 percent in 2003, due to the changing supply and demand needs on the Company's generation system.

Variations in MWH sales for the three years are reflected in the following table:

	2003	**Increase/ (Decrease)**	2002	Increase/ (Decrease)	2001	Increase/ (Decrease)
System Sales (A)	**25.0**	**1.6%**	24.6	0.4%	24.5	(2.0)%
Off-System Sales (A)	**0.1**	**(67.0)%**	0.3	(25.0)%	0.4	33.3%
Total Sales	**25.1**	**0.8%**	24.9	---	24.9	(1.6)%

(A) Sales are in millions of MWHs.

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. 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 – State Restructuring Initiatives and National Energy Legislation" for a discussion of the potential impact on competition from federal and state legislation.

OKLAHOMA GAS AND ELECTRIC COMPANY
CERTAIN OPERATING STATISTICS

Year ended December 31 *(In millions)*	**2003**	2002	2001
ELECTRIC ENERGY			
(Millions of MWH)			
Generation (exclusive of station use)	**22.5**	23.4	23.0
Purchased	**4.5**	3.5	3.7
Total generated and purchased	**27.0**	26.9	26.7
Company use, free service and losses	**(1.9)**	(2.0)	(1.8)
Electric energy sold	**25.1**	24.9	24.9
ELECTRIC ENERGY SOLD			
(Millions of MWH)			
Residential	**8.2**	8.0	8.0
Commercial and industrial	**12.6**	12.4	12.4
Public street and highway lighting	**0.1**	0.1	0.1
Other sales to public authorities	**2.6**	2.6	2.5
System sales for resale	**1.5**	1.5	1.5
Total system sales	**25.0**	24.6	24.5
Off-system sales	**0.1**	0.3	0.4
Total sales	**25.1**	24.9	24.9
ELECTRIC OPERATING REVENUES			
(In millions)			
Residential	**$ 601.4**	$ 557.6	$ 578.9
Commercial and industrial	**665.9**	605.5	638.0
Public street and highway lighting	**11.1**	10.4	10.9
Other sales to public authorities	**135.0**	125.1	127.9
System sales for resale	**57.7**	48.2	52.5
Provision for FERC rate refund	**---**	---	(1.0)
Total system sales	**1,471.1**	1,346.8	1,407.2
Off-system sales	**4.1**	6.3	13.0
Total Electric Revenues	**1,475.2**	1,353.1	1,420.2
Miscellaneous revenues	**41.9**	34.9	36.6

Total Electric Operating Revenues	$ **1,517.1**	$ 1,388.0	$ 1,456.8
ACTUAL NUMBER OF ELECTRIC CUSTOMERS			
(At end of period)			
Residential	**622,527**	616,712	609,408
Commercial and industrial	**89,235**	88,466	87,511
Public street and highway lighting	**249**	249	250
Other sales to public authorities	**13,409**	13,031	12,566
Sales for resale	**50**	55	62
Total	**725,470**	718,513	709,797
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	$ **970.04**	$ 907.95	$ 952.32
Average annual use (kilowatt-hour ("KWH"))	**13,202**	13,095	13,131
Average price per KWH (cents)	$ **7.35**	$ 6.93	$ 7.25

Regulation and Rates

The Company's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. 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 FERC. The Secretary of the Department of Energy has jurisdiction over some of the Company's facilities and operations. For the year ended December 31, 2003, approximately 87 percent of the Company's electric revenue was subject to the jurisdiction of the OCC, nine percent to the APSC and four percent to the FERC.

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 Energy Corp. to employ accounting and other procedures and controls to protect against subsidization of non-utility activities by the Company's customers; and prohibit Energy Corp. from pledging Company assets or income for affiliate transactions.

2002 Settlement Agreement

On October 11, 2002, the Company, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to the Settlement Agreement of the Company's rate case. The administrative law judge subsequently recommended approval of the Settlement Agreement and on November 22, 2002, the OCC signed a rate order containing the provisions of the Settlement Agreement. The Settlement Agreement provides for, among other items: (i) a $25.0 million annual reduction in the electric rates of the Company's Oklahoma customers which went into effect January 6, 2003; (ii) recovery by the Company, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) the Company to acquire electric generation ("New Generation") of not less than 400 megawatts ("MW") to be integrated into the Company's generation system; and (iv) recovery by the Company, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through the Company's rider for off-system sales. Previously, the Company had a 50/50 sharing mechanism in Oklahoma for any off-system sales. The Settlement Agreement provided that the first $1.8 million in annual net profits from the Company's off-system sales will go to the Company, the next $3.6 million in annual net profits from off-system sales will go to the Company's Oklahoma customers, and any net profits of off-system sales in excess of these amounts will be credited in each sales year with 80 percent to the Company's Oklahoma customers and the remaining 20 percent to the Company. If any of the $5.4 million is not recovered at the end of the three years, the OCC will authorize the recovery of any remaining costs.

Pending Acquisition of Power Plant

As part of the 2002 Settlement Agreement with the OCC, the Company undertook to acquire New Generation of not less than 400 MWs. The acquisition of a 77 percent interest in the 520 MW NRG McClain Station (the "McClain Plant") would clearly constitute an acquisition of such New Generation under the Settlement Agreement. The Company expects this New

Generation, including the interim purchase power agreement, will provide savings, over a three-year period, in excess of $75.0 million to its Oklahoma customers. These savings will be derived from: (i) the avoidance of purchase power contracts otherwise needed; (ii) replacing an above market cogeneration contract with PowerSmith Cogeneration Project, L.P. ("PowerSmith") when it can be terminated at the end of August 2004; and (iii) fuel savings associated with operating efficiencies of the new plant. These savings, while providing real savings to Oklahoma customers, are not expected to affect the profitability of the Company because the Company's rates would not need to be reduced to accomplish these savings. As indicated in the Settlement Agreement, the Company is required to provide monthly reports, for a period of 36 months after the acquisition, to the OCC Staff, documenting and providing proof of savings experienced by the Company's customers. In the event the Company is unable to demonstrate at least $75.0 million in savings to its customers during this 36-month period, the Company will have an obligation to credit its Oklahoma customers any unrealized savings below $75.0 million as determined at the end of the 36-month period, which shall be no later than December 31, 2006. PowerSmith has filed an application with the OCC seeking to compel the Company to continue purchasing power from PowerSmith's qualified cogeneration facility under the Public Utility Regulatory Policy Act of 1978 ("PURPA") at a price that would include an avoided capacity charge equal to the lesser of (i) the rate currently specified in the power purchase agreement between the Company and PowerSmith or (ii) the avoided cost of the McClain Plant. The Company does not believe that this matter should be heard at the OCC at this time and that the avoided cost requested by PowerSmith is too high. In the event PowerSmith is ultimately successful and the Company is required to sign a purchase power agreement, it could negatively affect the Company's ability to achieve the targeted $75 million three-year customer savings under the existing terms of the Settlement Agreement. PowerSmith and the Company have been holding discussions to determine if mutually agreeable terms can be reached for a power contract between the companies providing for capacity payments to the PowerSmith facility.

In the event the Company did not acquire the New Generation by December 31, 2003, the Settlement Agreement requires the Company to credit $25.0 million annually (at a rate of 1/12 of $25.0 million per month for each month that the New Generation is not in place) to its Oklahoma customers beginning January 1, 2004 and continuing through December 31, 2006. However, if the Company purchases the New Generation subsequent to January 1, 2004, the credit to Oklahoma customers will terminate in the first month that the New Generation begins initial operations and any previously-credited amounts to Oklahoma customers will be deducted in the determination of the $75.0 million targeted savings.

On August 18, 2003, the Company signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the McClain Plant. The acquisition of this interest in the McClain Plant would clearly constitute an acquisition of New Generation under the Settlement Agreement. The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. The McClain Plant includes natural gas-fired combined cycle combustion turbine units and is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001. The owner of the remaining 23 percent in the McClain Plant is the Oklahoma Municipal Power Authority ("OMPA").

Closing is subject to customary conditions including receipt of regulatory approval by the FERC. The asset purchase agreement, as amended, provides that, unless extended, either party has the right to terminate the contract if the closing does not occur on or before March 16, 2004. Because the current owner of the McClain Plant has filed for bankruptcy protection, the acquisition also was subject to approval by the bankruptcy court. As part of the bankruptcy approval process, NRG McClain LLC's interest in the plant was subject to an auction process and on October 28, 2003, the bankruptcy court approved the sale of NRG McClain LLC's interest in the plant to the Company. Several parties have filed interventions at the FERC opposing the Company's application under Section 203 of the Federal Power Act to acquire NRG McClain's interest in the power plant or, alternatively, requesting the FERC to delay approving such acquisition. The Company believed that its application met the standards under Section 203 set forth by the FERC and that its application would be approved. On December 18, 2003, the FERC shifted its policy regarding market power issues, raised wholesale market power concerns and ordered a hearing regarding the Company's acquisition of the McClain Plant. The FERC action did not reject the Company's request to purchase the McClain Plant, but demonstrated that the Company must address certain issues. On January 20, 2004, the Company filed a petition for re-hearing of the FERC's December 18, 2003 order which included new mitigation measures that were designed to allow for prompt approval of the transaction. That request is still pending before the FERC. The Company has no indication whether the FERC will accept those proposed mitigation measures. On March 2, 2004, the Company filed testimony and exhibits with the FERC administrative law judge. The testimony and exhibits indicate that, if the case proceeds to hearing, the wholesale market power issues that the FERC raised in the December 18, 2003 order may be resolved by the minimal mitigation measures.

Assuming the acquisition occurs, the Company expects to operate the plant in accordance with a joint ownership and operating agreement with the OMPA. Under this agreement, the Company would operate the facility, and the Company and the OMPA would be entitled to the net available output of the plant based on their respective ownership percentages. All fixed and variable costs, except fuel and gas transportation costs, would be shared in proportion to the respective ownership interests. Fuel and gas transportation costs would be shared based on consumption. The Company expects to utilize its portion of the output, 400 MWs, to serve its native load. As provided in the Settlement Agreement, pending approval of a request to increase base rates to recover the investment in the plant, the Company will have the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. Upon approval by the OCC of the Company's request, all prudently incurred costs accrued through the regulatory asset within the 12-month period will be included in the Company's prospective cost of service.

Despite the delay at the FERC, an agreement to purchase power from the McClain Plant is enabling the Company to honor the customer savings as outlined in the Settlement Agreement. On January 8, 2004, the Company filed an application with the OCC and requested that the OCC confirm the steps that the Company has taken to comply with the Settlement Agreement will result in customer savings being delivered beginning January 1, 2004, and that no further rate reduction is necessary. Various parties have intervened opposing the Company's request. If the OCC does not agree with the Company's request, the Company will be required to reduce

electric rates to its Oklahoma customers by approximately $2.1 million per month and would expect to reduce expenditures for planned electric system reliability upgrades. The OCC has scheduled a hearing on April 19, 2004 for action in this case.

Assuming that the Company acquires the McClain Plant, the Company expects to fund the acquisition with a combination of a capital contribution from Energy Corp., funded in part by Energy Corp.'s equity issuance in 2003, and the issuance of long-term debt by the Company.

2003 Rate Case

On September 15, 2003, the Company filed with the OCC a notice of intent to seek an annual increase in its rates to its Oklahoma customers of more than one percent. The notice listed the following, among others, as major issues to be addressed in its application: (i) the acquisition of New Generation in accordance with the Settlement Agreement; (ii) increased capital expenditures for efficiency improvements and reliability enhancements to ensure fuel costs are minimized; and (iii) increased pension, medical and insurance costs. On October 31, 2003, the Company filed a request with the OCC to increase its rates by approximately $91 million annually. The increase was intended to pay for its pending acquisition of a 77 percent interest in the McClain Plant, allow for investment in electric system reliability and address rising business costs. The rate plan would have reduced rates for schools and more than 80,000 small businesses and non-profit organizations. On January 15, 2004, the Company filed an application to withdraw its request for a $91 million rate increase due to the delay at FERC in receiving the necessary approvals to complete the acquisition of the McClain Plant, which was a significant part of this rate case. An order dismissing the case was issued by the OCC on January 30, 2004. On December 18, 2003, the FERC issued an order setting for hearing the Company's proposed acquisition of the McClain Plant and on January 15, 2004, the FERC administrative law judge in charge of the hearing and the parties to the case agreed to a procedural schedule that would produce a decision on the McClain Plant acquisition no sooner than the third quarter of 2004. The Company expects to file another rate case in the near future to recover increased operating and capital expenditures.

Gas Transportation and Storage Agreement

As part of the Settlement Agreement, the Company also agreed to consider competitive bidding for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. The Company believes that in order for it to achieve maximum coal generation and ensure reliable electric service, it must have firm no-notice load following service for both gas transportation and gas storage. This type of service is required to satisfy the daily swings in customer demand placed on the Company's system and still permit natural gas units to not impede coal energy production. The Company also believes that gas storage is an integral part of providing gas supply to the Company's generation facilities. Accordingly, the Company evaluated its competitive bid options in light of these circumstances. The Company's evaluation clearly demonstrates that the Enogex integrated gas system provides superior firm no-notice load following service to the Company that is not available from other companies serving the Company marketplace. On April 29, 2003, the Company filed an application with the OCC in which the Company advised the OCC that, after careful

consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of the Company's natural gas-fired generation facilities. During 2003, the Company paid Enogex approximately $44.7 million for gas transportation and storage services. Based upon requests for information from intervenors, the Company has requested from Enogex and Enogex has agreed to retain a "cost of service" consultant to assist in the preparation of testimony related to this case. On January 30, 2004, the OCC issued a procedural schedule for this case. A hearing is scheduled August 10-11, 2004 and an OCC order in the case is expected by the end of 2004. The Company believes the amount currently paid to Enogex for no-notice load following transportation and storage services is fair, just and reasonable. If any amounts paid by the Company are found not to be recoverable, the Company believes such amount would not be material.

Security Enhancements

On April 8, 2002, the Company filed a joint application with the OCC requesting approval for security investments and a rider to recover these costs from the ratepayers. On August 14, 2002, the Company filed testimony with the OCC outlining proposed expenditures and related actions for security enhancement and a proposed recovery rider. Attempting to make security investments at the proper level, the Company has developed a set of guidelines intended to minimize long-term or widespread outages, minimize the impact on critical national defense and related customers, maximize the ability to respond to and recover from an attack, minimize the financial impact on the Company that might be caused by an attack and accomplish these efforts with minimal impact on ratepayers. The OCC Staff retained a security expert to review the report filed by the Company. The Company currently expects that hearings will be held in early 2004.

On October 17, 2003, the OCC filed a notice of inquiry to consider the issues related to the role of the OCC and Oklahoma regulated companies in addressing the security of the electrical system infrastructure and key assets. On March 4, 2004, the OCC deliberated the notice of inquiry and directed the OCC Staff to file a rulemaking proceeding for each utility industry regarding security of the electrical system infrastructure and key assets.

Other Regulatory Actions

The Settlement Agreement, when it became effective, provided for the termination of the Acquisition Premium Credit Rider ("APC Rider") and the Gas Transportation Adjustment Credit Rider ("GTAC Rider").

The APC Rider was approved by the OCC in March 2000 and was implemented by the Company to reflect 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 was to remove approximately $10.7 million annually from the amount being recovered by the Company from its Oklahoma customers in current rates.

In June 2001, the OCC approved a stipulation (the "Stipulation") to the competitive bid process of the Company's gas transportation service from Enogex. The Stipulation directed the Company to reduce its rates to its Oklahoma retail customers by approximately $2.7 million per year through the implementation of the GTAC Rider. The GTAC Rider was a credit for gas transportation cost recovery and was applicable to and became part of each Oklahoma retail rate schedule to which the Company's automatic fuel adjustment clause applies. As discussed above, the Settlement Agreement terminated the GTAC Rider. Consequently, these charges for gas transportation provided by Enogex are now included in base rates.

The Company's Generation Efficiency Performance Rider ("GEP Rider") expired in June 2002. The GEP Rider was established initially in 1997 in connection with the Company's 1996 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 percent) 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 percent) of the average fuel costs of other investor-owned utilities. In June 2000 the OCC made modifications to the GEP Rider which 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 January 1, 2002 and June 30, 2002, the Company recovered approximately $2.4 million under the GEP Rider.

State Restructuring Initiatives

Oklahoma

As previously reported, the Electric Restructuring Act of 1997 (the "1997 Act") was initially designed to provide retail customers in Oklahoma a choice 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 1997 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 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, this legislation called for a nine-member task force to further study the issues surrounding deregulation. The task force includes the Governor or his designee, the Oklahoma Attorney General, the OCC Chair and several legislative leaders, among others. In the 2003 legislative session, additional legislation was introduced to repeal the 1997 Act, but the 2003 legislative session ended without any further action to repeal the 1997 Act. It is unknown at this time whether the 1997 Act will be repealed. The Company will continue to actively participate in the legislative process and expects to remain a competitive supplier of electricity. As a result of the failures of California's attempt to

deregulate its electricity markets, the Enron bankruptcy, and associated impacts on the industry, efforts to restructure the electricity market in Oklahoma appear at this time to be delayed indefinitely.

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 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. In March 2003, the Restructuring Law was repealed. As part of the repeal legislation, electric public utilities are permitted to recover transition costs. The Company incurred approximately $2.4 million in transition costs necessary to carry out its responsibilities associated with efforts to implement retail open access. On January 20, 2004, the APSC issued an order which authorized the Company to recover approximately $1.9 million in transition costs over an 18-month period beginning February 2004.

Automatic Fuel Adjustment Clauses

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component in the cost-of-service for ratemaking, are passed through to the Company's customers through automatic fuel adjustment clauses, which are subject to periodic review by the OCC, the APSC and the FERC. The OCC is currently reviewing the appropriateness of gas transportation charges under the agreement between the Company and Enogex. See "Gas Transportation and Storage Agreement" for a further discussion. The Company believes the amount currently paid to Enogex for no-notice load following transportation and storage services is fair, just and reasonable. All of the storage costs and a portion of the gas transportation costs are included in either base rates or are recoverable through the Company's automatic fuel adjustment clause. See "Regulation and Rates – Other Regulatory Actions" for a further discussion.

National Energy Legislation

In December 2003 the U.S. Senate failed to pass a comprehensive Energy Bill that had long been debated in the Senate and the House of Representatives. The bill, as it was proposed, would have been largely beneficial to the Company. It contained provisions that would have minimized the risk of future uneconomic purchased power contracts being forced on the Company under PURPA as well as providing tax incentives for investment in the electric transmission and natural gas pipeline systems. The bill also provided favorable provisions for mandatory reliability oversight by the North American Electric Reliability Council with oversight by the FERC as well as the FERC citing authority for electric transmission in disputed areas. Also positive to the Company was that the bill did not contain any provisions for mandatory levels of renewable energy which would have had the effect of raising the Company's electric rates. Another significant provision of the Energy Bill was the repeal of the Public Utility Holding Company Act of 1935 which was of minimal impact to the Company.

When Congress reconvened in January 2004, the debate renewed over the Energy Bill. A compromise bill has been proposed in the Senate that would keep all of the issues important to the Company intact with the exception of the tax provisions. Excluding those provisions would eliminate the incentives for investment in the electric transmission and natural gas pipeline systems. It is unknown at this time what language will be contained in the final bill or when, or if, the bill is likely to be considered again in the Senate and the House of Representatives and, when or if, the bill ultimately will be approved.

Federal law imposes numerous responsibilities and requirements on the Company. PURPA requires electric utilities, such as the Company, to purchase power generated in a manufacturing process from a qualified cogeneration facility ("QF"). Generally stated, electric utilities must purchase electric energy and production capacity made available by QF's 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 QF's on a non-discriminatory basis at a rate that is just, reasonable and in the public interest and must provide certain types of service which may be requested by QF's to supplement or back up those facilities' own generation.

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

Notwithstanding these developments in the wholesale power market, the FERC recognized that impediments remained to the achievement of fully competitive wholesale markets including: (i) engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid; and (ii) continuing opportunities for transmission owners (primarily electric utilities) to discriminate in the operation of their transmission facilities in favor of their own or affiliated power marketing activities. In the past, the FERC only encouraged utilities to join and place their transmission systems under the operational control of independent system operators ("ISO"). On December 20, 1999, the FERC issued Order 2000, its final rule on regional transmission organizations ("RTO"). Order 2000 is intended to have the

effect of turning the nation's transmission facilities into independently operated "common carriers" that offer comparable service to all would-be-users. Although adopting a voluntary approach towards RTO formation, the FERC stressed that Order 2000 does not preclude it from requiring RTO participation. Order 2000 set out a timetable for every jurisdictional utility (including 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 all or parts of Oklahoma, Arkansas, Kansas, Louisiana, New Mexico, Mississippi, Missouri and 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 1998. 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 then 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 MISO and SPP organizations, 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. However, for a variety of reasons, MISO and SPP terminated their proposed combination in March 2003. The Company remained a member of the SPP while the MISO/SPP combination was pending, and the Company participated with the SPP and other SPP members to evaluate the next steps necessary for compliance with the FERC's Order 2000. In the meantime, the SPP continued to offer open access transmission service in the SPP region under the SPP Open Access Transmission Tariff. On October 15, 2003, the SPP filed an application with the FERC seeking authority to form an RTO. On February 10, 2004, the FERC conditionally approved the SPP's application. The SPP must meet certain conditions before it may commence operations as an RTO. Termination of the proposed MISO/SPP combination and recent conditional approval of the SPP RTO application are not expected to significantly impact the Company's financial results.

In October 2001, the FERC issued a Notice of Proposed Rulemaking proposing to adopt new standards of conduct rules applicable to all jurisdictional electric and natural gas transmission providers. The proposed rules would replace the current rules governing the electric transmission and wholesale electric functions of electric utilities and the rules governing natural gas transportation and wholesale gas supply functions. The proposed rules would expand the definition of "affiliate" and further limit communications between transmission functions and supply functions, and could materially increase operating costs of market participants, including the Company and Enogex. In April 2002, the FERC Staff issued a reaction paper, generally rejecting the comments of parties opposed to the proposed rules. On November 25, 2003, the FERC issued its new rules regulating the relationship between electric and gas transmission providers and those entities' merchant personnel and energy affiliates. The FERC's final rule requires all transmission providers to be in full compliance with the new rules by June 1, 2004.

On February 9, 2004, the Company submitted a plan and schedule to take the necessary actions to be in compliance with these new rules and expects that its initial costs to comply with the final rule will not exceed $0.5 million in 2004. The final rule is currently before the FERC on rehearing. Any changes to the final rule on rehearing could affect the anticipated compliance costs.

In July 2002, the FERC issued a Notice of Proposed Rulemaking on Standard Market Design Rulemaking for regulated utilities. If implemented as proposed, the rulemaking will substantially change how wholesale electric markets operate throughout the United States. The proposed rulemaking expands the FERC's intent to unbundle transmission operations from integrated utilities and ensure robust competition in wholesale markets. The proposed rule contemplates that all wholesale and retail customers will take transmission service under a single network transmission service tariff. The rule also contemplates the implementation of a bid-based system for buying and selling energy in wholesale markets. RTOs or Independent Transmission Providers will administer the market. RTOs will also be responsible for regional plans that identify opportunities to construct new transmission, generation or demand side programs to reduce transmission constraints and meet regional energy requirements. Finally, the rule envisions the development of Regional Market Monitors responsible for ensuring the individual participants do not exercise unlawful market power. On April 28, 2003, the FERC issued a White Paper, "Wholesale Market Platform", in which the FERC indicated that it will change the proposed rule as reflected in the White Paper and following additional regional technical conferences. The FERC committed in the White Paper to work with interested parties including state commissions to find solutions that will recognize regional differences within regions subject to the FERC's jurisdiction. Thus far, the FERC has held conferences in Boston, Omaha, Wilmington, Tallahassee, Phoenix, New York and San Francisco.

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

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

Regulatory Assets and Liabilities

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 the expected recovery from customers in future rates. Likewise, certain credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

The Company initially records certain costs: (i) that are probable of future recovery as a deferred charge until such time as the cost is approved by a regulatory authority, then the cost is reclassified as a regulatory asset; and (ii) that are probable of future liability as a deferred credit until such time as the amount is approved by a regulatory authority, then the amount is reclassified as a regulatory liability.

At December 31, 2003 and 2002, the Company had regulatory assets of approximately $94.2 million and $111.1 million, respectively, and regulatory liabilities of approximately $148.7 million and $109.3 million, respectively. Approximately 45 percent of the regulatory assets and liabilities are allocated to the Company's electric generation assets and approximately 55 percent of the regulatory assets and liabilities are allocated to the Company's electric transmission and distribution assets.

As discussed previously, legislation was enacted in Oklahoma and Arkansas that was to restructure the electric utility industry in those states. The Arkansas legislation was repealed and implementation of the Oklahoma restructuring legislation has been delayed and seems unlikely to proceed during the near future. Yet, if and when implemented this legislation would deregulate the Company's electric generation assets and cause the Company to discontinue the use of SFAS No. 71, with respect to its related regulatory balances. This may result in either full recovery of generation-related regulatory assets (net of related regulatory liabilities) or a non-cash, pre-tax write-off as an extraordinary charge, depending on the transition mechanisms developed by the legislature for the recovery of all or a portion of these net regulatory assets.

The previously enacted Oklahoma and Arkansas legislation would not affect 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 balances is appropriate. However, if utility regulators in Oklahoma and Arkansas were to adopt regulatory methodologies in the future that are not based on the cost-of-service, the continued use of SFAS No. 71 with respect to the regulatory balances related to the electric transmission and distribution assets may no longer be appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management believes that its regulatory assets, including those related to generation, are probable of future recovery.

Summary

The Energy Act, the actions of the FERC, the restructuring legislation in Oklahoma and other factors are intended to increase competition in the electric industry. 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

In 2002, the Company concluded its Oklahoma rate review proceeding before the OCC. This rate review was initiated in September 2001 by the OCC Staff and was concluded by order

of the OCC on November 20, 2002. Under the rate review, the Company, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to a Settlement Agreement which stipulated that the Company would file tariffs, designed to reflect an annual reduction of $25.0 million in the Company's Oklahoma jurisdictional operating revenue. The $25.0 million annual reduction began on January 6, 2003. The Settlement Agreement addressed the importance of the Company acquiring New Generation. See "Regulation and Rates – Pending Acquisition of Power Plant" for the issues facing the Company in its acquisition of the McClain Plant in accordance with the Settlement Agreement.

Other elements of importance addressed in the Settlement Agreement included a modification of the sharing ratio of off-system sales and the recognition of the reduction of cogeneration costs in the Company's retail rates in the years 2003 and beyond.

The Company also received OCC approval in the Settlement Agreement for several new customer programs and rate options, as well as modifications to existing rate structures. The Guaranteed Flat Bill ("GFB") option for residential and small general service accounts allows qualifying customers the opportunity to purchase their electricity needs at a set price for an entire year. Budget-minded customers that desire a fixed monthly bill benefit from the GFB option. A second tariff rate option approved in the Settlement Agreement is an offering to provide a "renewable energy" resource to the Company's Oklahoma retail customers. This renewable energy resource is a wind power purchase program and is available as a voluntary option to all of the Company's Oklahoma retail customers. Oklahoma's availability of wind resources makes the renewable wind power option a possible choice in meeting the renewable energy needs of our conservation-minded customers. A third new rate offering available to commercial and industrial customers is levelized demand billing. This program is beneficial for medium to large size customers with seasonally consistent demand levels who wish to reduce the variability of their monthly electric bills. The levelized demand offering is not for every customer, but many customers will benefit from this program. The last new program being offered to the Company's commercial and industrial customers and approved by the OCC is a new voluntary load curtailment program. This program provides customers with the opportunity to curtail on a voluntary basis when the Company's system conditions merit curtailment action. Customers that curtail their usage will receive payment for their curtailment response. This voluntary curtailment program seeks customers that can curtail on most curtailment event days, but may not be able to curtail every time that a curtailment event is required.

The previously discussed new rate options coupled with the Company's existing rate choices provide many tariff options for the Company's Oklahoma retail customers. The Company's rate choice flexibility, reduction in cogeneration rates, acquisition of additional generation resources and overall low costs of production and deliverability are expected to provide valuable benefits for our customers for many years to come. The Company began implementation of the new rate options during the first billing cycle in January 2003. Since many of these options are voluntary, customers may choose these options anytime after the January 2003 start date. The revenue impacts associated with these options are indeterminate in future years since customers may choose to remain on existing rate options instead of volunteering for the new rate option choices. There was no overall material impact in 2003

associated with these new rate options, but minimal revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose these new programs.

Fuel Supply

During 2003, approximately 77 percent of the Company-generated energy was produced by coal units and 23 percent by natural gas units. Of the 5,660 total MW capability reflected in the table under Item 2. Properties, approximately 3,125 MWs or 55 percent are from natural gas generation and approximately 2,535 MWs or 45 percent are from coal generation. Though the Company has a higher installed capability of generation from natural gas units of 55 percent, it has been more economical to generate electricity for our customers using lower priced coal. A slight decline in the percentage of coal generation in future years is expected to result from increased usage of natural gas generation required to meet growing energy needs. Over the last five years, the average cost of fuel used, by type, per million British thermal unit ("MMBtu") was as follows:

	2003	2002	2001	2000	1999
Coal	**$ 0.93**	$ 0.93	$ 0.81	$ 0.87	$ 0.85
Natural Gas	**$ 6.46**	$ 3.78	$ 4.91	$ 4.93	$ 3.14
Weighted Average	**$ 2.27**	$ 1.77	$ 1.97	$ 1.96	$ 1.54

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."

Coal

All of the Company's coal units, with an aggregate capability of approximately 2,535 MWs, are designed to burn low sulfur western coal. The Company purchases coal primarily under long-term contracts expiring in 2010 and 2011. During 2003, the Company purchased approximately 9.7 million tons of coal from the following Wyoming suppliers: Kennecott Energy Company, Arch Coal Inc., Peabody Coal Sales Company and Triton Coal Company. The combination of all coal has a weighted average sulfur content of less than 0.24 percent and can be burned in these units under existing federal, state and local environmental standards (maximum of 1.2 lbs. of sulfur dioxide per MMBtu) without the addition of sulfur dioxide removal systems. Based upon the average sulfur content, the Company's units have an approximate emission rate of 0.504 lbs. of sulfur dioxide per MMBtu well within the limitations of the provisions of Phase II of The Clean Air Act.

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.

Natural Gas

The Company utilized a request for bid ("RFB") to acquire approximately 42 percent of its projected annual natural gas requirements through approximately April 2004. These contracts are tied to various gas price market indices and most will expire in April 2004. A significant portion of future gas requirements of the Company will be secured through a new multi-year RFB that was issued in February 2004 with deliveries to begin in April 2004. Additional gas requirements of the Company will be met with monthly and day-to-day purchases as required.

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

FINANCE AND CONSTRUCTION

Future Capital Requirements

Capital Requirements

The Company's primary needs for capital are related to replacing or expanding existing facilities in its electric utility business. Other capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities and delays in recovering unconditional fuel purchase obligations. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings from Energy Corp. and permanent financings. See “Item 7. Management’s Discussion and Analysis of Financial Conditions and Results of Operations – Liquidity and Capital Requirements” for a detailed discussion of the Company’s capital requirements.

Variances in the actual cost of fuel used in electric generation (which includes the operating lease obligations for the Company’s railcar leases) 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 fuel related to operating leases and the vast majority of unconditional fuel 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 net capital requirements and future contractual obligations. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. See Note 12 of Notes to Financial Statements for a further discussion.

Capital Expenditures

The Company’s current 2004 to 2006 construction program includes the purchase of New Generation as discussed below. The Company currently has contracts with qualified cogeneration facilities and small power production producers’ (“QF contracts”) for the purchase of 540 MWs, all of which expire in the next one to five years. The Company will continue reviewing all of the supply alternatives to replace expiring QF contracts that minimize the total cost of generation to our customers. Accordingly, the Company will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, the Company will also assess the feasibility of constructing additional base load coal-fired units. See “Regulation and Rates – Pending Acquisition of Power Plant” for a description of current proceedings involving a PowerSmith QF contract.

On August 18, 2003, the Company signed an asset purchase agreement to acquire NRG McClain LLC’s 77 percent interest in the 520 MW McClain Plant. The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. Closing is currently delayed in response to an order of the FERC. See “Regulation and Rates – Pending Acquisition of Power Plant.” If approval is received, funding for the acquisition is to be provided by proceeds received by Energy Corp. from its equity

offering in the third quarter of 2003, and a debt issuance by the Company. To reliably meet the increased electricity needs of the Company’s customers during the foreseeable future, the Company will continue to invest to maintain the integrity of the delivery system. Approximately $5.8 million of the Company’s capital expenditures budgeted for 2004 are to comply with environmental laws and regulations.

Future Sources of Financing

General

Management expects that internally generated funds, funds received from Energy Corp. (from Energy Corp.’s 2003 equity offering and proceeds from the sales of its common stock pursuant to Energy Corp.’s Automatic Dividend Reinvestment and Stock Purchase Plan (“DRIP”)) and short-term debt will be adequate over the next three years to meet other anticipated capital expenditures, operating needs, payment of dividends and maturities of long-term debt. As discussed below, the Company utilizes short-term borrowings from Energy Corp. to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged. Later in 2004, assuming the acquisition of the McClain Plant is approved by the FERC, the Company plans to issue debt to fund the purchase of the McClain Plant and for general corporate purposes.

Short-Term Debt

Short-term borrowings from Energy Corp. generally are used to meet working capital requirements. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Requirements – Future Sources of Financing” for a table showing Energy Corp.’s and the Company’s lines of credit in place and available cash at January 31, 2004. Energy Corp.’s short-term borrowings are expected to consist of a 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 lines of credit contain rating grids that require annual fees and borrowing rates to increase if Energy Corp. suffers an adverse ratings impact. The impact of additional downgrades of Energy Corp.’s rating 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 rating changes.

The Company must obtain regulatory approval from the FERC in order to borrow on a short-term basis. The Company has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time.

Security Ratings

In January and February 2003, Standard & Poor’s Ratings Services (“Standard & Poor’s”) and Moody’s Investors Service (“Moody’s”) lowered the credit ratings of the Company’s debt. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of

Operations – Liquidity and Capital Requirements – Future Capital Requirements” for a more detailed discussion of such credit rating agency actions.

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

ENVIRONMENTAL MATTERS

Approximately $5.8 million of the Company's capital expenditures budgeted for 2004 are to comply with environmental laws and regulations.

The Company's management believes that all of its operations are in substantial compliance with present federal, state and local environmental standards. It is estimated that the Company's total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $56.0 million during 2004, compared to approximately $51.6 million utilized in 2003. 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.

In 2003, several pieces of national legislation were either introduced or reintroduced after having failed to pass in 2002. These bills could have required the reduction in emissions of sulfur dioxide ("SO2"), nitrogen oxide ("NOX"), carbon dioxide ("CO2") and mercury from the electric utility industry. Among the bills was President Bush's "Clear Skies" proposal. While not addressing CO2, this bill would require significant reductions in SO2, NOX and mercury emissions. As in 2002, none of the proposed legislation became law; however, it is expected that numerous multi-pollutant bills will again be introduced in 2004.

As required by Title IV of the Clean Air Act Amendments of 1990 ("CAAA"), the Company completed installation and certification of all required continuous emissions monitors at its generating stations in 1995. Since then, the Company has submitted emissions data quarterly to the Environmental Protection Agency ("EPA") as required by the CAAA. Beginning in 2000, the Company became subject to more stringent SO2 emission requirements. These lower limits had no significant financial impact due to the Company's earlier decision to burn low sulfur coal. In 2003, the Company's SO2 emissions were well below the allowable limits.

With respect to the NOX regulations of Title IV of the CAAA, the Company 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 2003 were 0.32 lbs/MMBtu. However, further reductions in NOX emissions could be required if, among other things, legislation is enacted, a study currently being conducted by the state of Oklahoma determines that such NOX emissions are contributing to regional haze and that the Company's facilities impact the air quality of the Tulsa or Oklahoma

City metropolitan areas, or if Oklahoma fails to meet the new fine particulate standards. Any of these scenarios would require significant capital and operating expenditures.

The Oklahoma Department of Environmental Quality's Clean Air Act Amendment Title V permitting program was approved by the EPA in March 1996. By March of 1997, the Company had submitted all required permit applications. As of December 31, 2003, 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 $0.6 million in 2003. The fees for 2004 are estimated to be approximately the same as in 2003.

Other potential air regulations have emerged that could impact the Company. On December 15, 2003, the EPA proposed regulations to limit mercury emissions from coal-fired boilers. This rule is expected to be finalized by early 2005. Earliest compliance by the Company would be January 2008. Depending upon the final regulations, this could result in significant capital and operating expenditures. In addition, on December 17, 2003, the EPA proposed an interstate air quality rule. This rule is intended to control SO2 and NOX from utility boilers in order to minimize the interstate transport of air pollution. In the proposed rule, the state of Oklahoma is exempt from any reductions. However this could change as the EPA has indicated its intentions to review Oklahoma's impact on other states. If Oklahoma is included in the final rule reductions, this could lead to significant capital and operating expenditures by the Company.

In 1997, the EPA finalized revisions to the ambient ozone and particulate standards. After a court challenge, which delayed implementation, the EPA has now begun to finalize the implementation process. Based on the most recent monitoring data, Oklahoma's Governor in July of 2003 proposed to the EPA that the entire state be designated attainment with the ozone standard. Later in 2003 the EPA approved Oklahoma's request. However, both Tulsa and Oklahoma City had previously entered into an "Early Action Compact" with the EPA whereby voluntary measures will be enacted to reduce ozone. In order to ensure that ozone levels remain below the standards, both cities intend to comply with the compact. Minimal impact on the Company's operations is expected.

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. However, Oklahoma's impact on parks in other states must also be evaluated. Sulfates and nitrate aerosols (both emitted from coal-fired boilers) can lead to the degradation of visibility. The State of Oklahoma has joined with eight other central states and has begun the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas. If an impact is determined, then significant capital expenditures could be required for both the Sooner and Muskogee generating stations.

While the United States has withdrawn its support of the Kyoto Protocol on global warming, legislation has been considered which would limit CO2 emissions. President Bush supports voluntary reductions by industry. The Company has joined other utilities in voluntary

CO2 sequestration projects through reforestation of land in the southern United States. In addition, the Company has committed to reduce its CO2 emission rate (lbs. CO2/MWH) by up to five percent over the next 10 years. However, if legislation is passed requiring mandatory reductions this could have a tremendous impact on the Company's operations by requiring the Company to significantly reduce the use of coal as a fuel source.

The Company has sought, and will continue to seek, new pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2003, the Company obtained refunds of approximately $0.5 million from its recycling efforts. This figure does not include the additional savings gained through the reduction and/or avoidance of disposal costs and the reduction in material purchases due to the reuse of existing materials. Similar savings are anticipated in future years.

The Company has submitted three applications during 2003 to renew its Oklahoma pollution discharge elimination system permits. The Company anticipates that the renewed permits will continue to allow operational flexibility.

The Company requested, based on the performance of a site-specific study, that the State agency responsible for the development of water quality standards adjust the in-stream copper criterion at one of its facilities. Adjustment of this criterion should allow the facility to avoid costly treatment and/or facility reconfiguration requirements. The State and the EPA have approved the new in-stream criteria for copper.

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. Final rules for existing utility sources were approved on February 16, 2004. Depending on the analysis of these final 316(b) rules, capital and/or operating costs may increase at some of the Company's generating facilities.

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.

EMPLOYEES

The Company had 1,926 employees at December 31, 2003.

ACCESS TO SECURITIES AND EXCHANGE COMMISSION FILINGS

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

Item 2. Properties.

The Company owns and operates an interconnected electric generation, transmission and distribution system, located in Oklahoma and western Arkansas, which includes eight generating stations with an aggregate capability of approximately 5,660 MWs. The following table sets forth information with respect to the Company's electric generating facilities, all of which are located in Oklahoma:

Station & Unit		Year Installed	Unit Design Type	Fuel Capability	Unit Run Type	2003 Capacity Factor (A)	Unit Capability (MWs)	Station Capability (MWs)
Seminole	1	1971	Steam-Turbine	Gas	Base Load	23.3%	520.4	
	2	1973	Steam-Turbine	Gas	Base Load	21.2%	507.6	
	3	1975	Steam-Turbine	Gas/Oil	Base Load	19.6%	489.0	1,517.0
Muskogee	3	1956	Steam-Turbine	Gas	Base Load	7.2%	166.0	
	4	1977	Steam-Turbine	Coal	Base Load	73.1%	500.5	
	5	1978	Steam-Turbine	Coal	Base Load	87.3%	514.0	
	6	1984	Steam-Turbine	Coal	Base Load	70.9%	502.0	1,682.5
Sooner	1	1979	Steam-Turbine	Coal	Base Load	82.1%	505.2	
	2	1980	Steam-Turbine	Coal	Base Load	79.9%	513.8	1,019.0
Horseshoe	6	1958	Steam-Turbine	Gas/Oil	Base Load	16.9%	168.5	
Lake	7	1963	Combined Cycle	Gas/Oil	Base Load	17.3%	227.5	
	8	1969	Steam-Turbine	Gas	Base Load	8.0%	380.5	
	9	2000	Combustion-Turbine	Gas	Peaking	2.3%(B)	45.5	
	10	2000	Combustion-Turbine	Gas	Peaking	6.1%(B)	45.5	867.5
Mustang	1	1950	Steam-Turbine	Gas	Peaking	0.6%(B)	53.0	
	2	1951	Steam-Turbine	Gas	Peaking	0.7%(B)	53.0	
	3	1955	Steam-Turbine	Gas	Base Load	16.6%	115.5	
	4	1959	Steam-Turbine	Gas	Base Load	21.9%	250.0	
	5	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	0.7%(B)	31.0	502.5

Conoco	1	1991	Combustion-Turbine	Gas	Base Load	56.1%	31.5	
	2	1991	Combustion-Turbine	Gas	Base Load	57.8%	31.0	62.5
Enid	1	1965	Combustion-Turbine	Gas	Peaking	--- (C)	---	
	2	1965	Combustion-Turbine	Gas	Peaking	--- (C)	---	
	3	1965	Combustion-Turbine	Gas	Peaking	--- (C)	---	
	4	1965	Combustion-Turbine	Gas	Peaking	--- (C)	---	---
Woodward	1	1963	Combustion-Turbine	Gas	Peaking	--- (B)	9.4	9.4
Total Generating Capability (all stations)								5,660.4

(A) 2003 Capacity Factor = 2003 Net Actual Generation / (2003 Net Maximum Capacity (Nameplate Rating in MWs) x Period Hours (8,760 Hours)).
(B) Peaking units, which are used when additional capacity is required, are also necessary to meet the SPP reserve margins.
(C) These units are currently inactive.

At December 31, 2003, the Company's transmission system included: (i) 32 substations with a total capacity of approximately 14.2 million kilo Volt-Amps ("kVA") and approximately 3,959 structure miles of lines in Oklahoma; and (ii) two substations with a total capacity of approximately 1.5 million kVA and approximately 252 structure miles of lines in Arkansas. The Company's distribution system included: (i) 340 substations with a total capacity of approximately 9.3 million kVA, 22,494 structure miles of overhead lines, 1,859 miles of underground conduit and 7,565 miles of underground conductors in Oklahoma; and (ii) 36 substations with a total capacity of approximately 1.4 million kVA, 1,870 structure miles of overhead lines, 224 miles of underground conduit and 442 miles of underground conductors in Arkansas.

During the three years ended December 31, 2003, the Company's gross property, plant and equipment additions were approximately $481.9 million and gross retirements were approximately $96.0 million. These additions were provided by internally generated funds from operating cash flows, short-term borrowings from Energy Corp. and permanent financings. The additions during this three-year period amounted to approximately 11.3 percent of total property, plant and equipment at December 31, 2003.

Item 3. Legal Proceedings.

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

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 the city held 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 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, which is a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleges: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and Btu content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees.

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

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

In October 2002, the Court granted the Department of Justice's motion to dismiss certain of Plaintiff's claims and issued an order dismissing Plaintiff's valuation claims against all defendants. Various procedural motions have been filed. Discovery is proceeding on limited jurisdiction issues as ordered by the Court. The deposition of relator Grynberg began in December 2002, and continued during 2003.

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company at this time.

3. *Will Price (Price I)* - On September 24, 1999, various subsidiaries of Energy Corp. were served with a class action petition filed in United States District Court, State of Kansas by Quinque Operating Company and other named plaintiffs, alleging mismeasurement of natural gas on non-federal lands. On April 10, 2003 the Court entered an order denying class certification. On May 12, 2003, Plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended petition and the court granted the motion on July 28, 2003. In this amended petition, the Company and Enogex Inc. were omitted from the case. Two subsidiaries of Enogex remain as defendants. The Plaintiffs' amended petition alleges that approximately 60 defendants, including two Enogex subsidiaries, have improperly measured natural gas. The amended petition reduces the claims to: (1) mismeasurement of volume only; (2) conspiracy, unjust enrichment and accounting; (3) a putative Plaintiffs' class of only royalty owners; and (4) gas measured in three specific states. Discovery on class certification is proceeding.

Energy Corp. intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, Energy Corp. is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to Energy Corp. at this time.

4. The Company has been sued by Kaiser-Francis Oil Company in District Court, Blaine County, Oklahoma. This case has been pending for more than 10 years. Plaintiff alleges that the Company breached the terms of numerous contracts covering approximately 60 wells by failing to purchase gas from Plaintiff in amounts set forth in the contracts. Plaintiff seeks $20.0 million in take-or-pay damages and $1.8 million in underpayment damages. Over the objection and unsuccessful appeal by the Company, Plaintiff has been permitted to amend its petition to include a claim based on theories of tort. Specifically, Plaintiff alleges, among other things, that the Company intentionally and tortuously interfered with contracts by falsifying documents, sponsoring false testimony and putting forward legal defenses, which are known by the Company to be without merit. If successful, Plaintiff believes that these theories could give Plaintiff a basis to seek punitive damages. The Company believes that, to the extent Plaintiff were successful on the merits of its claims of the Company's failure to take gas, these amounts would be recoverable through its regulated electric rates. The claims related to tortuous conduct, which the Company believes at this time are without merit, would not appear to be properly recoverable in its electric rates. This lawsuit has been stayed pending the outcome of an appeal that the

Company filed in a similar case brought by Kaiser-Francis in Grady County. In the Grady case, the Company is appealing a verdict against it in the amount of approximately $8.0 million, including pre-judgment interest and attorneys' fees. While the Company cannot predict the precise outcome of the Grady case or this lawsuit, the Company believes, based on the information known at this time, that this lawsuit will not have a material adverse effect on the Company's financial position or results of operations.

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 January 31, 2004:

Name	Age	Title
Steven E. Moore	57	Chairman of the Board, President

		and Chief Executive Officer
Al M. Strecker	60	Executive Vice President and Chief Operating Officer
James R. Hatfield	46	Senior Vice President and Chief Financial Officer
Jack T. Coffman	60	Senior Vice President - Power Supply
Steven R. Gerdes	47	Vice President - Utility Operations and Shared Services
Michael G. Davis	54	Vice President - Business Systems and Services
Donald R. Rowlett	46	Vice President and Controller
Deborah S. Fleming	48	Treasurer
Gary D. Huneryager	53	Internal Audit Officer
Carla D. Brockman	44	Corporate Secretary

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Moore, Strecker, Hatfield, Gerdes, Davis, Rowlett and Huneryager, Ms. Fleming and Ms. Brockman are also officers of Energy Corp. Each Officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Stockholders, currently scheduled for May 20, 2004.

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	1999 - Present:	Chairman of the Board, President and Chief Executive Officer of Energy Corp. and the Company
Al M. Strecker	1999 - Present:	Executive Vice President and Chief Operating Officer of Energy Corp. and the Company
James R. Hatfield	2000 - Present:	Senior Vice President and Chief Financial Officer of Energy Corp. and the Company
	1999 - 2000:	Senior Vice President, Chief Financial Officer and Treasurer of Energy Corp. and the Company
Jack T. Coffman	1999 - Present:	Senior Vice President - Power Supply of the Company
Steven R. Gerdes	2003 - Present:	Vice President - Utility Operations and Shared Services of Energy Corp. and the Company
	1999 - 2003:	Vice President - Shared Services of Energy Corp. and the Company
Michael G. Davis	2004 - Present	Vice President - Business Systems and Services of Energy Corp. and the Company
	2002 - 2003:	Vice President - Process Management of the Company
	1999 - 2002:	Vice President - Marketing and Customer Care of the Company
Donald R. Rowlett	1999 - Present:	Vice President and Controller of Energy Corp. and the Company

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Deborah S. Fleming	2003 - Present:	Treasurer of Energy Corp. and the Company
	2000 - 2003:	Assistant Treasurer - Williams Cos. Inc.
	1999 - 2000:	Director of Corporate Finance - Williams Cos. Inc. (energy company)
Gary D. Huneryager	2002 - Present:	Internal Audit Officer of Energy Corp. and the Company
	2001 - 2002:	Assistant Internal Audit Officer of Energy Corp. and the Company
	1999 - 2001:	Service Line Director (Business Process Outsourcing) - Arthur Andersen LLP
Carla D. Brockman	2002 - Present:	Corporate Secretary of Energy Corp. and the Company
	2002:	Assistant Corporate Secretary of Energy Corp. and the Company
	1999 - 2002:	Client Manager - Strategic Planning of Energy Corp. and the Company

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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.

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Item 6. Selected Financial Data.

HISTORICAL DATA

	2003	2002	2001	2000	1999
SELECTED FINANCIAL DATA *(In millions)*					
Operating revenues	**$ 1,517.1**	$ 1,388.0	$ 1,456.8	$ 1,453.6	$ 1,286.8
Cost of goods sold	**837.4**	695.8	766.5	752.4	600.0
Gross margin on revenues	**679.7**	692.2	690.3	701.2	686.8
Other operating expenses	**463.5**	453.1	453.7	430.1	417.3
Operating income	**216.2**	239.1	236.6	271.1	269.5
Other income	**0.8**	0.7	1.1	0.1	1.0
Other expense	**3.2**	3.1	3.5	2.8	2.3
Net interest expense	**38.2**	39.0	43.6	45.7	44.2
Income tax expense	**60.2**	71.6	69.4	80.3	85.0
Net income	**$ 115.4**	$ 126.1	$ 121.2	$ 142.4	$ 139.0
Long-term debt	**$ 707.2**	$ 710.5	$ 700.4	$ 702.6	$ 593.0
Total assets	**$ 2,775.2**	$ 2,659.9	$ 2,549.8	$ 2,548.1	$ 2,433.6
CAPITALIZATION RATIOS (A)					
Stockholders' equity	**56.54%**	56.00%	56.93%	56.91%	59.99%
Long-term debt	**43.46%**	44.00%	43.07%	43.09%	40.01%

RATIO OF EARNINGS TO FIXED CHARGES (B)					
Ratio of earnings to fixed charges	**5.11**	5.41	4.80	5.16	5.45

(A) Capitalization ratios = [Stockholders' equity / (Stockholders' equity + Long-term debt)] and [Long-term / (Stockholders' equity + Long-term debt)].

(B) For purposes of computing the ratio of earnings to fixed charges, (1) earnings consist of net income plus fixed charges, federal and state income taxes, deferred income taxes and investment tax credits (net); and (2) fixed charges consist of interest on long-term debt, related amortization, interest on short-term borrowings and a calculated portion of rents considered to be interest.

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

Introduction

Oklahoma Gas and Electric Company (the "Company") generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas and is subject to regulation by 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 was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. The Company sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

Company Strategy

In early 2002, Energy Corp. completed a review of its business strategy that was largely driven by the anticipated deregulation of the retail electric markets in Oklahoma and Arkansas. Due to a variety of factors, including the current efforts to repeal the Oklahoma Electric Restructuring Act of 1997 and the recent repeal of the Restructuring Law in Arkansas, Energy Corp. does not anticipate that deregulation of the electricity markets in Oklahoma or Arkansas will occur in the foreseeable future. The strategic direction of Energy Corp. has been revised to reflect these developments. As a result, Energy Corp. expects potentially slower earnings growth than associated with deregulation but with less variability of those earnings.

Energy Corp.'s revised business strategy will utilize the diversified asset position of the Company and Energy Corp.'s wholly-owned natural gas pipeline subsidiary, Enogex Inc. and subsidiaries ("Enogex"), to provide energy products and services to customers primarily in the south central United States. Energy Corp. will focus on those products and services with limited or manageable commodity exposure. Energy Corp. intends for the Company to continue as a vertically integrated utility engaged in the generation, transmission and the distribution of electricity and to represent over time approximately 70 percent of Energy Corp.'s consolidated assets. The remainder of Energy Corp.'s consolidated assets will be in Enogex's businesses. At December 31, 2003, the Company and Enogex represented approximately 61 percent and 35 percent, respectively, of Energy Corp.'s consolidated assets. The remaining four percent of Energy Corp.'s consolidated assets were primarily at the holding company. In addition to the incremental growth opportunities that Enogex provides, Energy Corp. believes that Enogex's risk management capabilities, commercial skills and market information provide value to all of Energy Corp.'s businesses. Federal regulation in regard to the operations of the wholesale power market may change with the evolving policy at the FERC. In addition, Oklahoma and Arkansas legislatures and utility commissions may propose changes from time to time that could subject utilities to market risk. Accordingly, the Company is applying risk management practices to all of its operations in an effort to mitigate the potential adverse effect of any future regulatory changes.

In the near term, the Company plans on increasing its investment and growing earnings largely through the acquisition of electric generation ("New Generation"). As discussed in more detail below, in August 2003, the Company signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the 520 megawatt ("MW") NRG McClain Station (the "McClain Plant"). In December 2003, the FERC delayed approval of the acquisition citing market power concerns. On January 15, 2004, the FERC administrative law judge in charge of the hearing and the parties to the case agreed to a procedural schedule that would produce a decision on the McClain Plant acquisition no sooner than the third quarter of 2004. The Company subsequently withdrew its request before the OCC to increase its rates by approximately $91 million annually to cover the costs of the acquisition. Despite the delay at the FERC, an agreement to purchase power from the McClain Plant is enabling the Company to honor the customer savings as outlined in the agreed settlement of the Company's rate case (the "Settlement Agreement"). The Company will continue to monitor the FERC's recent shift in policy regarding market power issues around the McClain Plant acquisition to determine the practicability of future power plant purchases in addition to purchased power contracts. See "Overview – Pending Acquisition of Power Plant" for a further discussion including a potential $2.1 million per month rate reduction. The Company also plans to increase its capital expenditures in the foreseeable future for electric system reliability upgrades which is consistent with our commitment to our Customer Savings and Reliability Plan outlined in the Company's rate case filed with the OCC on October 31, 2003.

The Company currently has contracts with qualified cogeneration facilities and small power production producers' ("QF contracts") for the purchase of 540 MWs, all of which expire in the next one to five years. The Company will continue reviewing all of the supply alternatives to replace expiring QF contracts that minimize the total cost of generation to our customers. Accordingly, the Company will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, the Company will also assess the feasibility of constructing additional base load coal-fired units.

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in "2004 Outlook", are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit, actions of ratings agencies and their impact on capital expenditures; Energy Corp.'s ability and the ability of its subsidiaries to obtain financing on favorable terms; 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; changes in accounting standards, rules or guidelines; creditworthiness of suppliers, customers, and other contractual parties; completion of the pending acquisition of a power plant; an adverse decision

by the OCC requiring the Company to reduce its rates and the other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission.

Overview

General

The following discussion and analysis presents factors which affected the Company's results of operations for the years ended December 31, 2003, 2002 and 2001 and the Company's financial position at December 31, 2003 and 2002. The following information should be read in conjunction with the Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

Operating Results

2003 compared to 2002. The Company reported net income of approximately $115.4 million and $126.1 million for the years ended December 31, 2003 and 2002, respectively. The decrease in net income during 2003 as compared to 2002 was primarily attributable to lower electric rates as a result of the $25 million electric rate reduction that went into effect in Oklahoma on January 6, 2003, weaker weather-related demand and higher operating and maintenance expenses partially offset by customer growth in the Company's service territory.

2002 compared to 2001. The Company reported net income of approximately $126.1 million and $121.2 million for the years ended December 31, 2002 and 2001, respectively. The increase in net income during 2002 as compared to 2001 is primarily attributable to lower operating and maintenance expenses, lower interest expenses and increased growth in the Company's service territory partially offset by lower levels of natural gas transportation cost recovered, lower recoveries of fuel costs from Arkansas customers, loss of revenue resulting from the January 2002 ice storm, lower sales to other utilities and power marketers ("off-system sales"), milder weather and higher depreciation expense.

2002 Settlement Agreement

On October 11, 2002, the Company, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to the Settlement Agreement of the Company's rate case. The administrative law judge subsequently recommended approval of the Settlement Agreement and on November 22, 2002, the OCC signed a rate order containing the provisions of the Settlement Agreement. The Settlement Agreement provides for, among other items: (i) a $25.0 million annual reduction in the electric rates of the Company's Oklahoma customers which went into effect January 6, 2003; (ii) recovery by the Company, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) the Company to acquire New Generation of not less than 400 MWs to be integrated into the Company's generation system; and (iv) recovery by the Company, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through the Company's rider for off-system sales. Previously, the Company had a 50/50 sharing mechanism in Oklahoma for any off-system sales. The Settlement Agreement provided that the first $1.8 million in annual net profits from the

Company's off-system sales will go to the Company, the next $3.6 million in annual net profits from off-system sales will go to the Company's Oklahoma customers, and any net profits of off-system sales in excess of these amounts will be credited in each sales year with 80 percent to the Company's Oklahoma customers and the remaining 20 percent to the Company. If any of the $5.4 million is not recovered at the end of the three years, the OCC will authorize the recovery of any remaining costs.

Pending Acquisition of Power Plant

As part of the 2002 Settlement Agreement with the OCC, the Company undertook to acquire New Generation of not less than 400 MWs. The acquisition of a 77 percent interest in the McClain Plant would clearly constitute an acquisition of such New Generation under the Settlement Agreement. The Company expects this New Generation, including the interim purchase power agreement, will provide savings, over a three-year period, in excess of $75.0 million to its Oklahoma customers. These savings will be derived from: (i) the avoidance of purchase power contracts otherwise needed; (ii) replacing an above market cogeneration contract with PowerSmith Cogeneration Project, L.P. ("PowerSmith") when it can be terminated at the end of August 2004; and (iii) fuel savings associated with operating efficiencies of the new plant. These savings, while providing real savings to Oklahoma customers, are not expected to affect the profitability of the Company because the Company's rates would not need to be reduced to accomplish these savings. As indicated in the Settlement Agreement, the Company is required to provide monthly reports, for a period of 36 months after the acquisition, to the OCC Staff, documenting and providing proof of savings experienced by the Company's customers. In the event the Company is unable to demonstrate at least $75.0 million in savings to its customers during this 36-month period, the Company will have an obligation to credit its Oklahoma customers any unrealized savings below $75.0 million as determined at the end of the 36-month period, which shall be no later than December 31, 2006. PowerSmith has filed an application with the OCC seeking to compel the Company to continue purchasing power from PowerSmith's qualified cogeneration facility under the Public Utility Regulatory Policy Act of 1978 ("PURPA") at a price that would include an avoided capacity charge equal to the lesser of (i) the rate currently specified in the power purchase agreement between the Company and PowerSmith or (ii) the avoided cost of the McClain Plant. The Company does not believe that this matter should be heard at the OCC at this time and that the avoided cost requested by PowerSmith is too high. In the event PowerSmith is ultimately successful and the Company is required to sign a purchase power agreement, it could negatively affect the Company's ability to achieve the targeted $75 million three-year customer savings under the existing terms of the Settlement Agreement. PowerSmith and the Company have been holding discussions to determine if mutually agreeable terms can be reached for a power contract between the companies providing for capacity payments to the PowerSmith facility.

In the event the Company did not acquire the New Generation by December 31, 2003, the Settlement Agreement requires the Company to credit $25.0 million annually (at a rate of 1/12 of $25.0 million per month for each month that the New Generation is not in place) to its Oklahoma customers beginning January 1, 2004 and continuing through December 31, 2006. However, if the Company purchases the New Generation subsequent to January 1, 2004, the credit to Oklahoma customers will terminate in the first month that the New Generation begins initial

operations and any previously-credited amounts to Oklahoma customers will be deducted in the determination of the $75.0 million targeted savings.

On August 18, 2003, the Company signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the McClain Plant. The acquisition of this interest in the McClain Plant would clearly constitute an acquisition of New Generation under the Settlement Agreement. The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. The McClain Plant includes natural gas-fired combined cycle combustion turbine units and is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001. The owner of the remaining 23 percent in the McClain Plant is the Oklahoma Municipal Power Authority ("OMPA").

Closing is subject to customary conditions including receipt of regulatory approval by the FERC. The asset purchase agreement, as amended, provides that, unless extended, either party has the right to terminate the contract if the closing does not occur on or before March 16, 2004. Because the current owner of the McClain Plant has filed for bankruptcy protection, the acquisition also was subject to approval by the bankruptcy court. As part of the bankruptcy approval process, NRG McClain LLC's interest in the plant was subject to an auction process and on October 28, 2003, the bankruptcy court approved the sale of NRG McClain LLC's interest in the plant to the Company. Several parties have filed interventions at the FERC opposing the Company's application under Section 203 of the Federal Power Act to acquire NRG McClain's interest in the power plant or, alternatively, requesting the FERC to delay approving such acquisition. The Company believed that its application met the standards under Section 203 set forth by the FERC and that its application would be approved. On December 18, 2003, the FERC shifted its policy regarding market power issues, raised wholesale market power concerns and ordered a hearing regarding the Company's acquisition of the McClain Plant. The FERC action did not reject the Company's request to purchase the McClain Plant, but demonstrated that the Company must address certain issues. On January 20, 2004, the Company filed a petition for re-hearing of the FERC's December 18, 2003 order which included new mitigation measures that were designed to allow for prompt approval of the transaction. That request is still pending before the FERC. The Company has no indication whether the FERC will accept those proposed mitigation measures. On March 2, 2004, the Company filed testimony and exhibits with the FERC administrative law judge. The testimony and exhibits indicate that, if the case proceeds to hearing, the wholesale market power issues that the FERC raised in the December 18, 2003 order may be resolved by the minimal mitigation measures.

Assuming the acquisition occurs, the Company expects to operate the plant in accordance with a joint ownership and operating agreement with the OMPA. Under this agreement, the Company would operate the facility, and the Company and the OMPA would be entitled to the net available output of the plant based on their respective ownership percentages. All fixed and variable costs, except fuel and gas transportation costs, would be shared in proportion to the respective ownership interests. Fuel and gas transportation costs would be shared based on consumption. The Company expects to utilize its portion of the output, 400 MWs, to serve its native load. As provided in the Settlement Agreement, pending approval of a request to increase base rates to recover the investment in the plant, the Company will have the right to accrue a

regulatory asset, for a period not to exceed 12 months subsequent to the acquisition, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. Upon approval by the OCC of the Company's request, all prudently incurred costs accrued through the regulatory asset within the 12-month period will be included in the Company's prospective cost of service.

Despite the delay at the FERC, an agreement to purchase power from the McClain Plant is enabling the Company to honor the customer savings as outlined in the Settlement Agreement. On January 8, 2004, the Company filed an application with the OCC and requested that the OCC confirm the steps that the Company has taken to comply with the Settlement Agreement will result in customer savings being delivered beginning January 1, 2004, and that no further rate reduction is necessary. Various parties have intervened opposing the Company's request. If the OCC does not agree with the Company's request, the Company will be required to reduce electric rates to its Oklahoma customers by approximately $2.1 million per month and would expect to reduce expenditures for planned electric system reliability upgrades. The OCC has scheduled a hearing on April 19, 2004 for action in this case.

Assuming that the Company acquires the McClain Plant, the Company expects to fund the acquisition with a combination of a capital contribution from Energy Corp., funded in part by Energy Corp.'s equity issuance in 2003, and the issuance of long-term debt by the Company.

2003 Rate Case

On September 15, 2003, the Company filed with the OCC a notice of intent to seek an annual increase in its rates to its Oklahoma customers of more than one percent. The notice listed the following, among others, as major issues to be addressed in its application: (i) the acquisition of New Generation in accordance with the Settlement Agreement; (ii) increased capital expenditures for efficiency improvements and reliability enhancements to ensure fuel costs are minimized; and (iii) increased pension, medical and insurance costs. On October 31, 2003, the Company filed a request with the OCC to increase its rates by approximately $91 million annually. The increase was intended to pay for its pending acquisition of a 77 percent interest in the McClain Plant, allow for investment in electric system reliability and address rising business costs. The rate plan would have reduced rates for schools and more than 80,000 small businesses and non-profit organizations. On January 15, 2004, the Company filed an application to withdraw its request for a $91 million rate increase due to the delay at FERC in receiving the necessary approvals to complete the acquisition of the McClain Plant, which was a significant part of this rate case. An order dismissing the case was issued by the OCC on January 30, 2004. On December 18, 2003, the FERC issued an order setting for hearing the Company's proposed acquisition of the McClain Plant and on January 15, 2004, the FERC administrative law judge in charge of the hearing and the parties to the case agreed to a procedural schedule that would produce a decision on the McClain Plant acquisition no sooner than the third quarter of 2004. The Company expects to file another rate case in the near future to recover increased operating and capital expenditures.

Gas Transportation and Storage Agreement

As part of the Settlement Agreement, the Company also agreed to consider competitive bidding for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. The Company believes that in order for it to achieve maximum coal generation and ensure reliable electric service, it must have firm no-notice load following service for both gas transportation and gas storage. This type of service is required to satisfy the daily swings in customer demand placed on the Company's system and still permit natural gas units to not impede coal energy production. The Company also believes that gas storage is an integral part of providing gas supply to the Company's generation facilities. Accordingly, the Company evaluated its competitive bid options in light of these circumstances. The Company's evaluation clearly demonstrates that the Enogex integrated gas system provides superior firm no-notice load following service to the Company that is not available from other companies serving the Company marketplace. On April 29, 2003, the Company filed an application with the OCC in which the Company advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of the Company's natural gas-fired generation facilities. During 2003, the Company paid Enogex approximately $44.7 million for gas transportation and storage services. Based upon requests for information from intervenors, the Company has requested from Enogex and Enogex has agreed to retain a "cost of service" consultant to assist in the preparation of testimony related to this case. On January 30, 2004, the OCC issued a procedural schedule for this case. A hearing is scheduled August 10-11, 2004 and an OCC order in the case is expected by the end of 2004. The Company believes the amount currently paid to Enogex for no-notice load following transportation and storage services is fair, just and reasonable. If any amounts paid by the Company are found not to be recoverable, the Company believes such amount would not be material.

Security Enhancements

On April 8, 2002, the Company filed a joint application with the OCC requesting approval for security investments and a rider to recover these costs from the ratepayers. On August 14, 2002, the Company filed testimony with the OCC outlining proposed expenditures and related actions for security enhancement and a proposed recovery rider. Attempting to make security investments at the proper level, the Company has developed a set of guidelines intended to minimize long-term or widespread outages, minimize the impact on critical national defense and related customers, maximize the ability to respond to and recover from an attack, minimize the financial impact on the Company that might be caused by an attack and accomplish these efforts with minimal impact on ratepayers. The OCC Staff retained a security expert to review the report filed by the Company. The Company currently expects that hearings will be held in early 2004.

On October 17, 2003, the OCC filed a notice of inquiry to consider the issues related to the role of the OCC and Oklahoma regulated companies in addressing the security of the electrical system infrastructure and key assets. On March 4, 2004, the OCC deliberated the

notice of inquiry and directed the OCC Staff to file a rulemaking proceeding for each utility industry regarding security of the electrical system infrastructure and key assets.

The Company has been and will continue to be affected by competitive changes to the utility industry. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although it appears unlikely in the near future that changes will occur to retail regulation in the states served by the Company due to the significant problems faced by California in its electric deregulation efforts and other factors, significant changes are possible, which could significantly change the manner in which the Company conducts its business. These developments at the federal and state levels are described in more detail below under "Electric Competition; Regulation."

2004 Outlook

Energy Corp. currently expects that consolidated earnings in 2004 will be between $1.40 and $1.50 per share, excluding any regulatory action that might affect the electric rates at the Company. For the Company, financial performance will depend to a large extent on regulatory considerations. The 2004 outlook includes expected net income of between $113 million and $117 million for the Company. In 2004, the Company plans to increase capital expenditures for electric system reliability upgrades.

During 2004, the Company anticipates slightly higher revenue than in 2003 based on sales growth of slightly less than two percent, normal weather and no change in base rates. Overall operating expenses are expected to grow at a rate of approximately 2.8 percent. The Company also assumes lower short-term interest costs for 2004 and the Company expects to increase capital expenditures to over $200 million for electric system reliability upgrades. Key factors affecting the Company's 2004 net income will be the result of pending regulatory proceedings, weather, the Company's ability to control operating and maintenance expenses and customer growth. If the OCC does not agree that the Company is delivering the customer savings as outlined in the Settlement Agreement, the Company may be required to credit to its Oklahoma customers approximately $2.1 million per month for each month that the New Generation is not in place. The Company has significant seasonality in its earnings. The Company typically shows minimal earnings or slight losses in the first and fourth quarters with a majority of earnings in the third quarter due to the seasonal nature of air conditioning demand.

Results of Operations

(In millions)	**2003**	2002	2001	Percent Change From Prior Year 2003	2002
Operating income	**$ 216.2**	$ 239.1	$ 236.6	(9.6)	1.1
Net income	**$ 115.4**	$ 126.1	$ 121.2	(8.5)	4.0

In reviewing its operating results, the Company believes that it is appropriate to focus on operating income as reported in its Statements of Income as operating income indicates the ongoing profitability of the Company excluding unusual or infrequent items, the cost of capital

and income taxes. Operating income was approximately $216.2 million, $239.1 million and $236.6 million in 2003, 2002 and 2001, respectively.

(In millions)	**2003**	2002	2001
Operating revenues	**$ 1,517.1**	$ 1,388.0	$ 1,456.8
Fuel	**544.5**	435.8	485.8
Purchased power	**292.9**	260.0	280.7
Gross margin on revenues	**679.7**	692.2	690.3
Other operating expenses	**463.5**	453.1	453.7
Operating income	**$ 216.2**	$ 239.1	$ 236.6
System sales - MWH (A)	**25.0**	24.6	24.5
Off-system sales - MWH	**0.1**	0.3	0.4
Total sales - MWH	**25.1**	24.9	24.9

(A) Megawatt-hour

2003 compared to 2002. The Company's operating income decreased approximately $22.9 million or 9.6 percent in 2003 as compared to 2002. The decrease in operating income was primarily attributable to lower electric rates as a result of the $25 million electric rate reduction that went into effect in Oklahoma on January 6, 2003, weaker weather-related demand, lower off-system sales and higher operating and maintenance expenses partially offset by customer growth in the Company's service territory.

Gross margin on revenues ("gross margin"), which is operating revenues less cost of goods sold, was approximately $679.7 million in 2003 as compared to approximately $692.2 million in 2002, a decrease of approximately $12.5 million or 1.8 percent. The gross margin primarily decreased due to lower electric rates as a result of the $25 million electric rate reduction that went into effect in Oklahoma on January 6, 2003 (approximately $24.8 million). Gross margin also was reduced by approximately $2.0 million due to weaker weather-related demand. Lower off-system sales decreased the gross margin by approximately $1.9 million as off-system sales can vary based upon the supply and demand needs on the Company's generation system. Partially offsetting these decreases in gross margin was an increase of approximately $17.5 million due to customer growth in the Company's service territory.

Cost of goods sold for the Company consists of fuel used in electric generation and purchased power. Fuel expense increased approximately $108.7 million or 24.9 percent in 2003 as compared to 2002 primarily due to a 29.4 percent increase in the average cost of fuel per kilowatt-hour ("Kwh"). 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 2003, the Company's fuel mix was 77 percent coal and 23 percent natural gas. Though the Company has a higher installed capability of generation from natural gas units of 55 percent, it has been more economical to generate electricity for our customers with lower priced coal. Purchased power costs increased approximately $32.9 million or 12.7 percent in 2003 as compared to 2002. The increase was primarily due to approximately a 28.2 percent increase in the volume of energy purchased primarily due to economic purchases.

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. While the regulatory mechanisms for recovering fuel costs differ in Oklahoma and Arkansas, in both states the costs are passed through to customers and are intended to provide neither an ultimate benefit nor detriment to the Company. 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 Enogex. See Note 12 of Notes to Financial Statements.

Other operating expenses, consisting of operating and maintenance expense, depreciation expense and taxes other than income, increased approximately $10.4 million or 2.3 percent in 2003 as compared to 2002. The Company's operating and maintenance expense increased approximately $11.9 million or 4.2

percent in 2003 as compared to 2002. The increase was primarily due to approximately a $10.7 million increase in pension and benefit expenses in 2003 as compared to 2002, due to the general upward trend in these costs. Also contributing to the increase in operating and maintenance expenses was the recognition of approximately $5.4 million for costs incurred during the first quarter of 2002 in connection with the severe January 2002 ice storm being reported as a regulatory asset. These 2002 expenditures, incurred by field service personnel, would normally have been charged to maintenance expenses in 2002. The increased operating and maintenance expenses were partially offset by a decrease in bad debt expense of approximately $3.5 million due to improved collection efforts.

Depreciation expense decreased approximately $1.3 million or 1.1 percent in 2003 as compared to 2002 due to a change made in the depreciation rate of production plant in 2003 as required by the Settlement Agreement.

2002 compared to 2001. The Company's operating income increased approximately $2.5 million or 1.1 percent in 2002 as compared to 2001. The increase in operating income was primarily attributable to a slightly higher gross margin due to growth in electric usage in the Company's service territory and lower operating and maintenance expenses partially offset by lower levels of natural gas transportation cost recovered, lower recoveries of fuel costs from Arkansas customers, loss of revenue resulting from the January 2002 ice storm, lower off-system sales and milder weather.

Gross margin was approximately $692.2 million in 2002 as compared to approximately $690.3 million in 2001, an increase of approximately $1.9 million or 0.3 percent. Growth in the number of customers in the Company's service territory and the resulting increase in electric sales of approximately 2.9 percent increased the gross margin by approximately $20.1 million. The increase was offset by lower recoveries of fuel costs from Arkansas customers through that state's automatic fuel adjustment clause of approximately $5.9 million. In Arkansas, recovery of fuel costs is subject to a bandwidth mechanism. If fuel costs are within the bandwidth range, recoveries are not adjusted on a monthly basis; rather they are reset annually on April 1. Gross margin also was reduced by approximately $4.0 million due to milder weather. Lower recoveries under the Generation Efficiency Performance Rider ("GEP Rider"), which terminated in June 2002, decreased the gross margin by approximately $3.6 million in 2002. Additionally, lower

levels of natural gas transportation cost that the Company was allowed to recover from its customers as a result of the Acquisition Premium Credit Rider ("APC Rider") and the Gas Transportation Adjustment Credit Rider ("GTAC Rider") decreased the gross margin by approximately $2.1 million. See Note 12 of Notes to Financial Statements for a further discussion of these riders. Although total expenditures from the January 2002 ice storm of approximately $92.0 million, which have been capitalized or deferred, did not impact operating results, the related loss of revenue due to interruption of service to our customers resulted in a decrease in the gross margin of approximately $1.5 million in 2002. Reduced amounts of off-system sales decreased the gross margin by approximately $1.1 million as off-system sales can vary based upon the supply and demand needs on the Company's generation system.

Fuel expense decreased approximately $50.0 million or 10.3 percent in 2002 as compared to 2001 primarily due to an 11.1 percent decrease in the average cost of fuel per Kwh. In 2002, the Company's fuel mix was 72 percent coal and 28 percent natural gas. Purchased power costs decreased approximately $20.7 million or 7.4 percent in 2002 as compared to 2001. This decrease was primarily due to approximately a 4.6 percent decrease in the volume of energy purchased and a 2.6 percent decrease in the cost of purchased energy per Kwh.

Other operating expenses decreased approximately $0.6 million or 0.1 percent in 2002 as compared to 2001. The Company's operating and maintenance expense decreased approximately $4.4 million or 1.5 percent in 2002 as compared to 2001. This decrease was primarily due to a decrease of approximately $11.5 million in bad debt expense, a decrease of approximately $1.8 million in materials and supplies expense and a decrease of approximately $1.0 million in contract labor costs. Higher than normal bills driven by high natural gas prices early in 2001, along with customer cut-off moratoriums imposed during high temperature periods during the summer of 2001 contributed to significantly increased uncollectibles in 2001. The decrease in contract labor costs was due to higher contract labor costs incurred in 2001 due to the use of contractors to supplement the Company's own crews to restore power after a major ice storm at the beginning of 2001 and a major wind storm in the early summer of 2001. The decreased operating and maintenance expenses were partially offset by an increase in employee pension and benefit costs of approximately $9.9 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 benefit obligation. The general upward trend in medical costs also contributed to the increase in employee benefit costs.

Depreciation expense increased approximately $3.3 million or 2.8 percent in 2002 as compared to 2001 due to a higher level of depreciable plant. Taxes other than income increased approximately $0.5 million or 1.1 percent in 2002 as compared to 2001 due to higher ad valorem taxes.

Other Income and Expense, Interest Expense and Income Tax Expense

2003 compared to 2002. Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $38.2 million in 2003 as compared to approximately $39.0 million in 2002, a decrease of approximately $0.8 million or 2.1 percent. This decrease was primarily due to a reduction in interest expense of approximately

$0.7 million related to lower interest rates on outstanding debt achieved from entering into an interest rate swap agreement.

Income tax expense was approximately $60.2 million in 2003 as compared to approximately $71.6 million in 2002, a decrease of approximately $11.4 million or 15.9 percent. The decrease was primarily due to lower pre-tax income for the Company as well as a greater deduction for the Company's Employee Stock Ownership Plan dividends in 2003, which reduced taxable income as compared to 2002.

2002 compared to 2001. Other income includes, among other things, contract work performed by the Company, non-operating rental income, gain on the sale of assets, profit on the retirement of fixed assets and miscellaneous non-operating income. Other income was approximately $0.7 million in 2002 as compared to approximately $1.1 million in 2001, a decrease of approximately $0.4 million or 36.4 percent. This decrease was primarily due to approximately a $0.3 million decrease in non-operating rental income.

Other expense includes, among other things, expenses from loss on the sale of assets, loss on retirement of fixed assets, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions. Other expense was approximately $3.1 million in 2002 as compared to approximately $3.5 million in 2001, a decrease of approximately $0.4 million or 11.4 percent. This decrease was primarily due to approximately a $0.2 million decrease in miscellaneous charitable donations and approximately a $0.1 million decrease in expenditures for certain civic, political and related activities.

Net interest expense was approximately $39.0 million in 2002 as compared to approximately $43.6 million in 2001, a decrease of approximately $4.6 million or 10.6 percent. This decrease was primarily due to a reduction in interest expense of approximately $2.9 million related to lower interest rates on outstanding debt achieved from entering into an interest rate swap agreement. Also contributing to the decrease was approximately a $1.9 million decrease in interest expense due to Energy Corp. related to lower borrowings in 2002. These decreases were partially offset by approximately a $0.5 million increase in interest expense due to an increase in commercial paper service fees.

Income tax expense was approximately $71.6 million in 2002 as compared to approximately $69.4 million in 2001, an increase of approximately $2.2 million or 3.2 percent primarily due to higher pre-tax income for the Company in 2002.

Financial Condition

The balance of Accounts Receivable – Customers, Net was approximately $123.1 million and $97.7 million at December 31, 2003 and 2002, respectively, an increase of approximately $25.4 million or 26.0 percent. The increase was primarily due to an increase in the Company's fuel costs in 2003 as compared to 2002 and increased usage due to customer growth in the Company's service territory, which increases were only partially offset by the rate reduction ordered for the Company that went into effect on January 6, 2003 and weaker weather-related demand.

The balance of Advances to Parent was approximately $51.8 million at December 31, 2003. There were no advances to parent at December 31, 2002. The increase was primarily due to commercial paper issued by the Company in anticipation of the completion of the McClain Plant acquisition. Due to a delay in the completion of the McClain Plant acquisition, the Company transferred these funds to Energy Corp.

The balance of Accrued Unbilled Revenues was approximately $38.0 million and $28.2 million at December 31, 2003 and 2002, respectively, an increase of approximately $9.8 million or 34.8 percent. Accrued unbilled revenues represent the amount of customers' electricity consumption that has not been billed at the end of each month. An amount is accrued as a receivable for this unbilled revenue based on usages and prices during the period. The increase was primarily due to an increase in the Company's fuel costs in 2003 as compared to 2002 and increased usage due to customer growth in the Company's service territory partially offset by weaker weather-related demand.

The balance of Fuel Clause Over Recoveries (net of Fuel Clause Under Recoveries) was approximately $28.4 million at December 31, 2003. The balance of Fuel Clause Under Recoveries was approximately $14.7 million at December 31, 2002. The increase in fuel clause over recoveries was due to over recoveries from the Company's customers as the amount billed during 2003 exceeded the Company's cost of fuel. The cost of fuel subject to recovery through the fuel clause mechanism was approximately $1.21 per MMBtu in December 2003, and was approximately $1.54 per MMBtu in December 2002. The Company's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, the Company under recovers fuel cost in periods of rising prices above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses allow the Company to amortize under or over recovery. The Company began amortizing the under collected amounts for 2002 beginning with the April 2003 customers bills.

The balance of Prepaid Benefit Obligation was approximately $37.5 million and $29.6 million at December 31, 2003 and 2002, respectively, an increase of approximately $7.9 million or 26.7 percent. The increase was due to Energy Corp.'s pension plan funding during the third quarter of 2003, of which a portion was allocated to the Company, partially offset by a decrease due to pension accruals being credited to the prepaid benefit obligation.

The balance of Short-Term Debt was approximately $50.0 million at December 31, 2003. There was no short-term debt outstanding at December 31, 2002. The increase was due to commercial paper borrowings in anticipation of the completion of the McClain Plant acquisition. Due to a delay in the completion of the McClain Plant acquisition, in January 2004, the Company repaid the outstanding commercial paper balance.

The balance of Advances from Parent was approximately $101.1 million at December 31, 2002. There were no advances from parent at December 31, 2003. The decrease was primarily due to a change in the tax method of accounting as discussed in Note 5 of Notes to Financial Statements.

The balance of Accrued Pension and Benefit Obligations was approximately $134.8 million and $148.6 million at December 31, 2003 and 2002, respectively, a decrease of approximately $13.8 million or 9.3 percent. The decrease was primarily due to a decrease in the liability associated with Energy Corp.'s pension plan, of which a portion was allocated to the Company. See Note 10 of Notes to Financial Statements for a further discussion.

Off-Balance Sheet Arrangements

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

Research Bulletin No. 51” in an unconsolidated entity that is held by, and material to, the Company, where such entity provides financing, liquidity, market risk or credit risk support to, or engages in leasing, hedging or research and development services with, the Company. The Company has the following off-balance sheet arrangements.

Heat Pump Loans

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 for a minimum of $1,500 to a maximum of $13,000 with a term of six months to 84 months. The finance rate is based upon market rates and is reviewed and updated periodically. The interest rates were 11.55 percent and 10.99 percent at December 31, 2003 and 2002, respectively.

The Company sold approximately $8.5 million, $12.7 million and $25.0 million of its heat pump loans in December 2002, November 1999 and October 1998, respectively, as part of separate securitization transactions through OGE Consumer Loan 2002, LLC, OGE Consumer Loan II LLC and OGE Consumer Loan LLC, respectively. The following table contains information related to each securitization.

	2002	1999	1998
Date heat pump loans sold	December 2002	November 1999	October 1998
Total amount of heat pump loans sold (in millions)	$ 8.5	$ 12.7	$ 25.0
Heat pump loan balance at December 31, 2003 (in millions)	$ 5.9	$ 2.1	$ 0.4
Note interest rate	5.25%	8.00%	6.75%
Base servicing fee rate (paid monthly)	0.375%	0.375%	0.375%
Trustee/custodian fees (paid quarterly) (in whole dollars)	$ 1,250	$ 1,250	$ 1,250
Owner trustee fees (paid annually) (in whole dollars)	$ 4,000	$ 4,000	$ 4,000
Sole director’s fee (paid quarterly) (in whole dollars)	$ 1,125	$ 625	$ 625
Loss exposure by securitization issue (in millions)	$ 0.8	$ 0.3	$ ---

Railcar Leases

At December 31, 2003, the Company has noncancellable operating leases which have purchase options covering 1,479 coal hopper railcars to transport coal from Wyoming to the Company’s coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through the Company’s tariffs and automatic fuel adjustment clauses. At the end of the lease term which is March 31, 2006, the Company has the option to purchase the railcars at a stipulated fair market value. If the Company chooses not to purchase the railcars, the Company has a loss exposure up to approximately $9.0 million related to the fair market value of the railcars to the extent the fair market value is less than 80 percent of the lessor’s cost of equipment. The Company is also required to maintain the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

Liquidity and Capital Requirements

The Company’s primary needs for capital are related to replacing or expanding existing facilities in its electric utility business. Other capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities and delays in recovering unconditional fuel purchase obligations. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings from Energy Corp. and permanent financings.

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

(In millions)	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Capital expenditures including AFUDC	$ 775.0	$ 365.0(A)	$ 410.0	N/A	N/A
Maturities of long-term debt	707.2	---	109.8	$ ---	$ 597.4
Pension funding obligations	43.5	43.5	N/A	N/A	N/A
Total capital requirements	1,525.7	408.5	519.8	---	597.4
Operating lease obligations					
Railcars	57.6	5.4	10.9	10.9	30.4
Other purchase obligations and commitments					
Cogeneration capacity payments	414.9	152.8	174.3	87.8	N/A
Fuel minimum purchase commitments	942.0	160.8	320.9	307.9	152.4
Other	5.0	5.0	---	---	---

Total other purchase obligations and commitments	1,361.9	318.6	495.2	395.7	152.4
Total capital requirements, operating lease obligations and other purchase obligations and commitments	2,945.2	732.5	1,025.9	406.6	780.2
Amounts recoverable through automatic fuel adjustment clause (B)	(1,419.5)	(324.0)	(506.1)	(406.6)	(182.8)
Total, net	$ 1,525.7	$ 408.5	$ 519.8	$ ---	$ 597.4

(A) Includes approximately $165 million related to the acquisition of the McClain Plant.
(B) Includes expected recoveries of costs incurred for the Company's railcar operating lease obligations and the Company's unconditional fuel purchase obligations.
N/A – not applicable

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

automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. See Note 12 of Notes to Financial Statements for a further discussion.

2003 Capital Requirements and Financing Activities

Total capital requirements, consisting of capital expenditures, maturities and retirements of long-term debt and pension funding obligations, were approximately $187.5 million and contractual obligations, net of recoveries through automatic fuel adjustment clauses, were approximately $2.0 million resulting in total net capital requirements and contractual obligations of approximately $189.5 million in 2003. Approximately $6.4 million of the 2003 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $236.0 million and net contractual obligations of approximately $1.5 million totaling approximately $237.5 million in 2002, of which approximately $2.8 million was to comply with environmental regulations. Approximately $86.6 million of capital expenditures in 2002 were associated with the costs of the January 2002 ice storm, which severely damaged the Company's electric transmission and distribution systems. Excluding the ice storm, total net capital requirements would have been approximately $149.4 million. During 2003, the Company's sources of capital were internally generated funds from operating cash flows and short-term borrowings from Energy Corp. Energy Corp.'s short-term borrowings consist primarily of commercial paper and short-term bank loans. Energy Corp. uses its commercial paper to fund changes in working capital and as an interim source of financing capital expenditures until permanent financing is arranged. The short-term debt balance at December 31, 2003 significantly increased from December 31, 2002 due to the planned acquisition of the McClain Plant, which has been delayed. Due to the delay in the completion of the McClain Plant acquisition, in January 2004, the Company repaid the outstanding commercial paper balance. Changes in working capital reflect the seasonal nature of the Company's business, the revenue lag between billing and collection for customers and fuel inventories. In 2002, Energy Corp. commercial paper was used to fund expenditures associated with the ice storm.

Interest Rate Swap Agreement

At December 31, 2003 and 2002, the Company had one outstanding interest rate swap agreement effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate. The objective of this interest rate swap was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. This interest rate swap qualified as a fair value hedge under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At December 31, 2003 and 2002, the fair values pursuant to the interest rate swap were approximately $4.0 million and $7.5 million, respectively, and are classified as Deferred Charges and Other Assets – Price Risk Management in the accompanying Balance Sheets. A corresponding net increase of approximately $4.0 million and $7.5 million was reflected in Long-

Term Debt at December 31, 2003 and 2002, respectively, as this fair value hedge was effective at December 31, 2003 and 2002.

Future Capital Requirements

Capital Expenditures

The Company's current 2004 to 2006 construction program includes the purchase of New Generation as discussed below. The Company currently has QF contracts for the purchase of 540 MWs, all of which expire in the next one to five years. The Company will continue reviewing all of the supply alternatives to replace expiring QF contracts that minimize the total cost of generation to our customers. Accordingly, the Company will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, the Company will also assess the feasibility of constructing additional base load coal-fired units. See Note 12 of Notes to Financial Statements for a description of current proceedings involving a PowerSmith QF contract.

On August 18, 2003, the Company signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the 520 MW McClain Plant. Closing has been delayed pending receipt of FERC approval. The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. See "Overview – Pending Acquisition of Power Plant." If approval is received, funding for the acquisition is to be provided by proceeds received by Energy Corp. from its equity offering in the third quarter of 2003, and a debt issuance by the Company. To reliably meet the increased electricity needs of the Company's customers during the foreseeable future, the Company will continue to invest to maintain the integrity of the delivery system. Approximately $5.8 million of the Company's capital expenditures budgeted for 2004 are to comply with environmental laws and regulations.

Pension and Postretirement Benefit Plans

During 2003, actual asset returns for Energy Corp.'s defined benefit pension plan were positively affected by growth in the equity markets. Approximately 61 percent of the pension plan assets are invested in listed common stocks with the balance invested in corporate debt and U.S. Government securities. For the year ended December 31, 2003, asset returns on the pension plan were approximately 22.76 percent. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline.

Energy Corp.'s contributions to the pension plan increased from approximately $48.8 million in 2002 to approximately $50.0 million in 2003, of which approximately $37.3 million and approximately $38.8 million were allocated to the Company in 2002 and 2003, respectively. This increase was necessitated by the lower investment returns on assets and lower discount rates used to value the accumulated pension benefit obligations. During 2004, Energy Corp. plans to contribute approximately $56.0 million to the pension plan, of which approximately $43.5 million is the Company's portion. The level of funding is dependent on returns on plan assets and future

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

	Change	Impact on Funded Status
Actual plan asset returns	+/- 5 percent	+/- $13.9 million
Discount rate	+/- 0.25 percent	+/- $16.3 million
Contributions	+ $10.0 million	+ $10.0 million
Expected long-term return on plan assets	+/- 1 percent	None

As discussed in Note 10 of Notes to Financial Statements, in 2000 Energy Corp. 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, Energy Corp.'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, Energy Corp.'s cash requirements should decrease and will be much less sensitive to changes in discount rates.

During 2003 and 2002, Energy Corp. made contributions to the pension plan that exceeded amounts previously recognized as net periodic pension expense and recorded a prepaid benefit obligation at December 31, 2003 and 2002 of approximately $55.7 million and $44.9 million, respectively, of which approximately $37.5 million and $29.6 million, respectively, were allocated to the Company. At December 31, 2003 and 2002, Energy Corp.'s projected pension benefit obligation exceeded the fair value of pension plan assets by approximately $131.8 million and $156.7 million, respectively, of which approximately $117.6 million and $137.8 million, respectively, were allocated to the Company. 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 $137.6 million and $163.9 million, respectively, for Energy Corp., of which approximately $122.8 million and $141.3 million, respectively, were allocated to the Company at December 31, 2003 and 2002. 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 2003 or 2002 and did not require a usage of cash and is therefore excluded from the accompanying 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.

Security Ratings

On October 31, 2002, Fitch Ratings ("Fitch") reaffirmed the rating of the Company's senior unsecured debt at AA- and short-term debt at F1. The rating outlook is stable as Fitch cited the solid financial position, low business risk and strong cash flows at the Company.

On January 15, 2003, Standard & Poor's Ratings Services ("Standard & Poor's") lowered the credit rating of the Company's senior unsecured debt from A- to BBB+. The outlook is now stable as Standard & Poor's cited the relatively low-risk low-cost efficient operations of the Company. The Company may experience somewhat higher borrowing costs but does not expect the actions by Standard & Poor's to have a significant impact on the Company's financial position, liquidity or results of operations.

On February 5, 2003, Moody's Investors Service ("Moody's") lowered the credit rating of the Company's senior unsecured debt to A2 from A1. The outlook for the Company is stable as Moody's cited the diminished credit profile of the Company with the Company having competitive generation and stable cash flow but with regulatory risk associated with the acquisition of at least 400 MWs of New Generation. The Company may experience somewhat higher borrowing costs but does not expect the actions by Moody's to have a significant impact on the Company's financial position, liquidity or results of operations.

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

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

Future Sources of Financing

Management expects that internally generated funds, funds received from Energy Corp. (from Energy Corp.'s 2003 equity offering and proceeds from the sales of its common stock pursuant to Energy Corp.'s Automatic Dividend Reinvestment and Stock Purchase Plan ("DRIP")) and short-term debt will be adequate over the next three years to meet other anticipated capital expenditures, operating needs, payment of dividends and maturities of long-term debt. As discussed below, the Company utilized short-term borrowings from Energy Corp. to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged. Later in 2004, assuming the acquisition of the McClain Plant is approved by the FERC, the Company plans to issue debt to fund the purchase of the McClain Plant and for general corporate purposes.

Short-Term Debt

Short-term borrowings from Energy Corp. generally are used to meet working capital requirements. The following table shows Energy Corp.'s and the Company's lines of credit in place and available cash at January 31, 2004. Energy Corp.'s short-term borrowings are expected to consist of a combination of bank borrowings and commercial paper.

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

Entity	Amount Available	Amount Outstanding	Maturity
Energy Corp. (A)	$ 15.0	$ ---	April 6, 2004
The Company	100.0	---	June 26, 2004
Energy Corp. (A)	300.0	---	December 9, 2004
Total	415.0	---	
Cash	31.0	N/A	N/A
Total	$ 446.0	$ ---	

(A) The lines of credit at Energy Corp. are used to back up its commercial paper borrowings, which were approximately $30.5 million at January 31, 2004. As shown in the table above, on December 11, 2003, Energy Corp. renewed its credit facility of $300.0 million maturing on December 9, 2004. This agreement has a one-year term.

Energy Corp.'s ability to access the commercial paper market could be adversely impacted by a commercial paper ratings downgrade. The lines of credit contain rating grids that require annual fees and borrowing rates to increase if Energy Corp. suffers an adverse ratings impact. The impact of additional downgrades of Energy Corp.'s rating 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 rating changes.

The Company must obtain regulatory approval from the FERC in order to borrow on a short-term basis. The Company has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time.

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

Critical Accounting Policies and Estimates

The Financial Statements and Notes to Financial Statements contain information that is pertinent to Management's Discussion and Analysis. 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. Changes to these assumptions and estimates could have a material effect on the Company's Financial Statements particularly as they relate to pension expense. However, the Company believes it has taken conservative positions, where assumptions and estimates are used, in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, contingency reserves, accrued removal obligations, regulatory assets and liabilities, unbilled revenue, the allowance for uncollectible accounts receivable and fair value hedging policies. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's audit committee.

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 effect on the amount of pension expense ultimately recognized. The pension plan rate assumptions are shown in Note 10 of Notes to Financial Statements. The assumed return on plan assets is based on management's expectation of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. See "Future Capital Requirements" for a further discussion.

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

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations," which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. The scope of SFAS No. 143 includes the Company's accrued plant removal costs for generation, transmission and distribution assets and requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of the fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of the fair value can be made. In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to retire certain assets. As the Company currently has no plans to retire any of these assets and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will monitor these assets and record a liability when a reasonable estimate of the fair value can be made. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its financial position or results of operations.

The Company engages in fair value hedge transactions to modify the rate composition of the debt portfolio. The Company has entered into an interest rate swap agreement on the debt portfolio to modify the interest rate exposure on fixed rate debt issues. This interest rate swap qualifies as a fair value hedge under SFAS No. 133. The objective of this interest rate swap was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards.

The Company, as a regulated utility, is subject to the accounting principles prescribed by SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 provides that certain costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment. At December 31, 2003 and 2002, regulatory assets (excluding recoverable take or pay gas charges) of approximately $61.7 million and $78.6 million, respectively, are being amortized and reflected in rates charged to customers over periods of up to 20 years. Recoverable take or pay gas charges are not reflected in rates charged to customers. See Note 11 of Notes to Financial Statements for a further discussion. At December 31, 2003 and 2002, regulatory liabilities (excluding fuel clause over recoveries) of approximately $116.3 million and $109.3 million, respectively, have been reclassified from Accumulated Depreciation in accordance with SFAS No. 143.

The Company initially records certain costs: (i) that are probable of future recovery as a deferred charge until such time as the cost is approved by a regulatory authority, then the cost is reclassified as a regulatory asset; and (ii) that are probable of future liability as a deferred credit until such time as the amount is approved by a regulatory authority, then the amount is reclassified as a regulatory liability.

The Company reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Balance Sheets and in Operating Revenues on the Statements of Income based on estimates of usage and prices during the period. At December 31, 2003, if the estimated usage or price used in the unbilled revenue calculation were to increase or decrease by one percent, this would cause a change in the unbilled revenues recognized of approximately $0.4 million. At December 31, 2003 and 2002, Accrued Unbilled Revenues were approximately $38.0 million and $28.2 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Customer balances are generally written off if not collected within six months after the original due date. The allowance for uncollectible accounts receivable is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. At December 31, 203, if the provision rate were to

increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of approximately $0.2 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Balance Sheets and is included in Other Operation and Maintenance Expense on the Statements of Income. The allowance for uncollectible accounts receivable was approximately $2.6 million and $4.7 million at December 31, 2003 and 2002, respectively.

Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. The scope of SFAS No. 143 includes the Company's accrued plant removal costs for generation, transmission and distribution assets and requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of the fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of the fair value can be made. Asset retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. The recognition of an asset retirement obligation is capitalized as part of the carrying amount of the long-lived asset. Asset retirement obligations represent future liabilities and, as a result, accretion expense is accrued on this liability until such time as the obligation is satisfied. Adoption of SFAS No. 143 was required for financial statements issued for fiscal years beginning after June 15, 2002. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its financial position or results of operations.

In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to retire certain assets. As the Company currently has no plans to retire any of these assets and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will monitor these assets and record a liability when a reasonable estimate of the fair value can be made.

SFAS No. 143 also requires that, if the conditions of SFAS No. 71 are met, a regulatory asset or liability should be recorded to recognize differences between asset retirement costs recorded under SFAS No. 143 and legal or other asset retirement costs recognized for ratemaking purposes. Upon the application of SFAS No. 143, all rate regulated entities that are subject to the statement requirements will be required to quantify the amount of previously accumulated asset retirement costs and reclassify those differences as regulatory assets or liabilities. At December 31, 2002, approximately $109.3 million had been previously recovered from ratepayers and recorded as a liability in Accumulated Depreciation related to estimated asset retirement obligations. This balance was reclassified as a regulatory liability on the December 31, 2002 Balance Sheet. At December 31, 2003, the regulatory liability for accrued removal obligations, net was approximately $116.3 million.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 addresses financial accounting and reporting for costs associated with exit and disposal activities and supersedes Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF 94-3. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. Adoption of SFAS No. 146 was required for exit and disposal activities initiated after December 31, 2002. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its financial position or results of operations.

In December 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." Interpretation No. 45 requires that at the time a company issues a guarantee, the company must recognize an initial liability for the fair value, or market value, of the obligations it assumes under that guarantee. Interpretation No. 45 is applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The Company adopted this new interpretation effective January 1, 2003 and the adoption of this new interpretation did not have a material impact on its financial position or results of operations.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51." Interpretation No. 46 requires the consolidation of entities in which an enterprise absorbs a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity. Currently, entities are generally consolidated by an enterprise when it has a controlling financial interest through ownership of a majority voting interest in the entity.

In October 2003, the FASB issued Interpretation No. 46-6, "Effective Date of FASB Interpretation No. 46, Consolidation of Variable Interest Entities," in which the FASB agreed to defer, for public companies, the required effective dates to implement Interpretation No. 46 for interests held in a variable interest entity ("VIE") or potential VIE that was created before February 1, 2003. For calendar year-end public companies, the deferral effectively moved the required effective date from the third quarter to the fourth quarter of 2003.

As a result of Interpretation No. 46-6, a public entity need not apply the provisions of Interpretation No. 46 to an interest held in a VIE or potential VIE until the end of the first interim or annual period ending after December 15, 2003, if the VIE was created before February 1, 2003 and the public entity has not issued financial statements reporting that VIE in accordance with Interpretation No. 46, other than in the disclosures required by Interpretation No. 46. Interpretation No. 46 may be applied prospectively with a cumulative-effect adjustment as of the date on which it is first applied or by restating previously issued financial statements for one or more years with a cumulative-effect adjustment as of the beginning of the first year restated. The Company adopted this new interpretation effective December 31, 2003 and the adoption of

this new interpretation did not have a material impact on its financial position or results of operations.

In April 2003, the FASB issued SFAS No. 149, "Amendments of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain instruments embedded in other contracts and for hedging activities under SFAS No. 133. This statement requires that contracts with comparable characteristics be accounted for similarly. In particular, this statement clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative, clarifies when a derivative contains a financing component, amends the definition of an underlying hedged risk to conform to language used in Interpretation No. 45 and amends certain other existing pronouncements. This statement, the provisions of which are to be applied prospectively, is effective for contracts entered into or modified after June

30, 2003 and for hedging relationships designated after June 30, 2003. The Company adopted this new standard effective July 1, 2003 and the adoption of this new standard did not have a material impact on its financial position or results of operations.

In December 2003, the FASB issued SFAS No. 132 (Revised), "Employers' Disclosures about Pensions and Other Postretirement Benefits, an amendment of FASB Statements No. 87, 88 and 106." This Statement revised employers' disclosures about pension plans and other postretirement benefits. It does not change the measurement or recognition of those plans required by FASB Statements No. 87, "Employers' Accounting for Pensions," No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," and No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." This Statement requires additional disclosures to those in the original Statement 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits," for defined benefit pension plans and other defined benefit postretirement plans. Additional disclosures include information describing the types of plan assets, investment strategy, measurement date, plan obligations, cash flows and the components of net periodic benefit cost recognized during interim periods. Adoption of the provisions of this statement, except the provisions related to foreign plans and estimated future benefit payments, is required for financial statements issued for fiscal years ending after December 15, 2003. Adoption of the interim provisions of this statement is required for interim periods beginning after December 15, 2003. Adoption of the provisions of this statement related to foreign plans and estimated future benefit payments is required for financial statements issued for fiscal years ending after June 15, 2004. The Company adopted this new standard effective December 31, 2003 and the adoption of this new standard did not have a material impact on its financial position or results of operations.

Electric Competition; Regulation

State Restructuring Initiatives

Oklahoma

As previously reported, the Electric Restructuring Act of 1997 (the "1997 Act") was initially designed to provide retail customers in Oklahoma a choice 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 1997 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 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, this legislation called for a nine-member task force to further study the issues surrounding deregulation. The task force includes the Governor or his designee, the Oklahoma Attorney General, the OCC Chair and several legislative leaders, among others. In the 2003 legislative session, additional legislation was introduced to repeal the 1997 Act, but the 2003 legislative session ended without any further action to repeal the 1997 Act. It is unknown at this time whether the 1997 Act will be repealed. The Company will continue to actively participate in the legislative process and expects to remain a competitive supplier of electricity. As a result of the failures of California's attempt to deregulate its electricity markets, the Enron bankruptcy, and associated impacts on the industry, efforts to restructure the electricity market in Oklahoma appear at this time to be delayed indefinitely.

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 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. In March 2003, the Restructuring Law was repealed. As part of the repeal legislation, electric public utilities are permitted to recover transition costs. The Company incurred approximately $2.4 million in transition costs necessary to carry out its responsibilities associated with efforts to implement retail open access. On January 20, 2004, the APSC issued an order which authorized the Company to recover approximately $1.9 million in transition costs over an 18-month period beginning February 2004.

National Energy Legislation

In December 2003 the U.S. Senate failed to pass a comprehensive Energy Bill that had long been debated in the Senate and the House of Representatives. The bill, as it was proposed, would have been largely beneficial to the Company. It contained provisions that would have minimized the risk of future uneconomic purchased power contracts being forced on the Company under PURPA as well as providing tax incentives for investment in the electric transmission and natural gas pipeline systems. The bill also provided favorable provisions for mandatory reliability oversight by the North American Electric Reliability Council with oversight by the FERC as well as the FERC citing authority for electric transmission in disputed areas. Also positive to the Company was that the bill did not contain any provisions for mandatory levels of renewable energy which would have had the effect of raising the Company's electric rates. Another significant provision of the Energy Bill was the repeal of the Public Utility Holding Company Act of 1935 which was of minimal impact to the Company.

When Congress reconvened in January 2004, the debate renewed over the Energy Bill. A compromise bill has been proposed in the Senate that would keep all of the issues important to the Company intact with the exception of the tax provisions. Excluding those provisions would eliminate the incentives for investment in the electric transmission and natural gas pipeline systems. It is unknown at this time what language will be contained in the final bill or when, or if, the bill is likely to be considered again in the Senate and the House of Representatives and, when or if, the bill ultimately will be approved.

Federal law imposes numerous responsibilities and requirements on the Company. PURPA requires electric utilities, such as the Company, to purchase power generated in a manufacturing process from a qualified cogeneration facility ("QF"). Generally stated, electric utilities must purchase electric energy and production capacity made available by QF's 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 QF's on a non-discriminatory basis at a rate that is just, reasonable and in the public interest and must provide certain types of service which may be requested by QF's to supplement or back up those facilities' own generation.

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

Notwithstanding these developments in the wholesale power market, the FERC recognized that impediments remained to the achievement of fully competitive wholesale markets including: (i) engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid; and (ii) continuing opportunities for transmission owners (primarily electric utilities) to discriminate in the operation of their transmission facilities in favor of their own or affiliated power marketing activities. In the past, the FERC only encouraged utilities to join and place their transmission systems under the operational control of independent system operators ("ISO"). On December 20, 1999, the FERC issued Order 2000, its final rule on regional transmission organizations ("RTO"). Order 2000 is intended to have the

effect of turning the nation's transmission facilities into independently operated "common carriers" that offer comparable service to all would-be-users. Although adopting a voluntary approach towards RTO formation, the FERC stressed that Order 2000 does not preclude it from requiring RTO participation. Order 2000 set out a timetable for every jurisdictional utility (including 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 all or parts of Oklahoma, Arkansas, Kansas, Louisiana, New Mexico, Mississippi, Missouri and 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 1998. 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 then 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 MISO and SPP organizations, 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. However, for a variety of reasons, MISO and SPP terminated their proposed combination in March 2003. The Company remained a member of the SPP while the MISO/SPP combination was pending, and the Company participated with the SPP and other SPP members to evaluate the next steps necessary for compliance with the FERC's Order 2000. In the meantime, the SPP continued to offer open access transmission service in the SPP region under the SPP Open Access Transmission Tariff. On October 15, 2003, the SPP filed an application with the FERC seeking authority to form an RTO. On February 10, 2004, the FERC conditionally approved the SPP's application. The SPP must meet certain conditions before it may commence operations as an RTO. Termination of the proposed MISO/SPP combination and recent conditional approval of the SPP RTO application are not expected to significantly impact the Company's financial results.

In October 2001, the FERC issued a Notice of Proposed Rulemaking proposing to adopt new standards of conduct rules applicable to all jurisdictional electric and natural gas transmission providers. The proposed rules would replace the current rules governing the electric transmission and wholesale electric functions of electric utilities and the rules governing natural gas transportation and wholesale gas supply functions. The proposed rules would expand the definition of "affiliate" and further limit communications between transmission functions and supply functions, and could materially increase operating costs of market participants, including the Company and Enogex. In April 2002, the FERC Staff issued a reaction paper, generally rejecting the comments of parties opposed to the proposed rules. On November 25, 2003, the FERC issued its new rules regulating the relationship between electric and gas transmission providers and those entities' merchant personnel and energy affiliates. The FERC's final rule requires all transmission providers to be in full compliance with the new rules by June 1, 2004.

On February 9, 2004, the Company submitted a plan and schedule to take the necessary actions to be in compliance with these new rules and expects that its initial costs to comply with the final rule will not exceed $0.5 million in 2004. The final rule is currently before the FERC on rehearing. Any changes to the final rule on rehearing could affect the anticipated compliance costs.

In July 2002, the FERC issued a Notice of Proposed Rulemaking on Standard Market Design Rulemaking for regulated utilities. If implemented as proposed, the rulemaking will substantially change how wholesale electric markets operate throughout the United States. The proposed rulemaking expands the FERC's intent to unbundle transmission operations from integrated utilities and ensure robust competition in wholesale markets. The proposed rule contemplates that all wholesale and retail customers will take transmission service under a single network transmission service tariff. The rule also contemplates the implementation of a bid-based system for buying and selling energy in wholesale markets. RTOs or Independent Transmission Providers will administer the market. RTOs will also be responsible for regional plans that identify opportunities to construct new transmission, generation or demand side programs to reduce transmission constraints and meet regional energy requirements. Finally, the rule envisions the development of Regional Market Monitors responsible for ensuring the individual participants do not exercise unlawful market power. On April 28, 2003, the FERC issued a White Paper, "Wholesale Market Platform", in which the FERC indicated that it will change the proposed rule as reflected in the White Paper and following additional regional technical conferences. The FERC committed in the White Paper to work with interested parties including state commissions to find solutions that will recognize regional differences within regions subject to the FERC's jurisdiction. Thus far, the FERC has held conferences in Boston, Omaha, Wilmington, Tallahassee, Phoenix, New York and San Francisco.

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

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

Regulatory Assets and Liabilities

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

The Company initially records certain costs: (i) that are probable of future recovery as a deferred charge until such time as the cost is approved by a regulatory authority, then the cost is reclassified as a regulatory asset; and (ii) that are probable of future liability as a deferred credit until such time as the amount is approved by a regulatory authority, then the amount is reclassified as a regulatory liability.

At December 31, 2003 and 2002, the Company had regulatory assets of approximately $94.2 million and $111.1 million, respectively, and regulatory liabilities of approximately $148.7 million and $109.3 million, respectively. Approximately 45 percent of the regulatory assets and liabilities are allocated to the Company's electric generation assets and approximately 55 percent of the regulatory assets and liabilities are allocated to the Company's electric transmission and distribution assets.

As discussed previously, legislation was enacted in Oklahoma and Arkansas that was to restructure the electric utility industry in those states. The Arkansas legislation was repealed and implementation of the Oklahoma restructuring legislation has been delayed and seems unlikely to proceed during the near future. Yet, if and when implemented this legislation would deregulate the Company's electric generation assets and cause the Company to discontinue the use of SFAS No. 71, with respect to its related regulatory balances. This may result in either full recovery of generation-related regulatory assets (net of related regulatory liabilities) or a non-cash, pre-tax write-off as an extraordinary charge, depending on the transition mechanisms developed by the legislature for the recovery of all or a portion of these net regulatory assets.

The previously enacted Oklahoma and Arkansas legislation would not affect 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 balances is appropriate. However, if utility regulators in Oklahoma and Arkansas were to adopt regulatory methodologies in the future that are not based on the cost-of-service, the continued use of SFAS No. 71 with respect to the regulatory balances related to the electric transmission and distribution assets may no longer be appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management believes that its regulatory assets, including those related to generation, are probable of future recovery.

Summary

The Energy Act, the actions of the FERC, the restructuring legislation in Oklahoma and other factors are intended to increase competition in the electric industry. 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.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third

parties, environmental actions or the action of various regulatory agencies. Management consults with counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Financial Statements. Except as set forth below, management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits and claims will have a material adverse effect on the Company's financial position, results of operations or cash flows. This assessment of currently pending or threatened lawsuits is subject to change.

Natural Gas Measurement Cases

Grynberg – On June 15, 1999, the Company was served with plaintiff's complaint, which is a qui tam action under the False Claims Act in the

United States District Court, State of Oklahoma by plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleging: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and British thermal unit ("Btu") content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees.

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

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

In October 2002, the Court granted the Department of Justice's motion to dismiss certain of Plaintiff's claims and issued an order dismissing Plaintiff's valuation claims against all defendants. Various procedural motions have been filed. Discovery is proceeding on limited jurisdiction issues as ordered by the Court. The deposition of relator Grynberg began in December 2002, and continued during 2003.

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, the Company is unable to provide an evaluation of the

likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company at this time.

Will Price (Price I) – On September 24, 1999, various subsidiaries of Energy Corp. were served with a class action petition filed in United States District Court, State of Kansas by Quinque Operating Company and other named plaintiffs, alleging mismeasurement of natural gas on non-federal lands. On April 10, 2003 the Court entered an order denying class certification. On May 12, 2003, Plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended petition and the court granted the motion on July 28, 2003. In this amended petition, the Company and Enogex Inc. were omitted from the case. Two subsidiaries of Enogex remain as defendants. The Plaintiffs' amended petition alleges that approximately 60 defendants, including two Enogex subsidiaries, have improperly measured natural gas. The amended petition reduces the claims to: (1) mismeasurement of volume only; (2) conspiracy, unjust enrichment and accounting; (3) a putative Plaintiffs' class of only royalty owners; and (4) gas measured in three specific states. Discovery on class certification is proceeding.

Energy Corp. intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, Energy Corp. is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to Energy Corp. at this time.

Pending Acquisition of Power Plant

On August 18, 2003, the Company signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the McClain Plant. Closing has been delayed pending receipt of FERC approval. The acquisition of this interest in the McClain Plant would clearly constitute an acquisition of New Generation under the Settlement Agreement. The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. See Note 12 of Notes to Financial Statements for a description of current proceedings involving a PowerSmith QF contract.

Sooner Power Plant Coal Dust Explosion

On February 16, 2004, there was a coal dust explosion at the Company's Sooner Power Plant which caused structural and electrical damage to the coal train unloading system. The generation capacity of the Sooner Plant facility has not been impacted by this incident. The estimated damage costs are between approximately $3.0 million and $4.0 million. The Company expects that the coal train unloading system will be ready to unload coal trains by April 2, 2004. In the meantime, Sooner Power Plant continues to generate power by using coal from the storage pile. Energy Corp. is self-insured for this loss.

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

Risk Management

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

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.

At December 31, 2003 and 2002, the Company had one outstanding interest rate swap agreement effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate. The objective of this interest rate swap was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. This interest rate swap qualified as a fair value hedge under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At December 31, 2003 and 2002, the fair values pursuant to the interest rate swap were approximately $4.0 million and $7.5 million, respectively, and are classified as Deferred Charges and Other Assets – Price Risk Management in the accompanying Balance Sheets. A corresponding net increase of approximately $4.0 million and $7.5 million was reflected in Long-Term Debt at December 31, 2003 and 2002, respectively, as this fair value hedge was effective at December 31, 2003 and 2002.

The fair value of the Company’s long-term debt is based on quoted market prices. The valuation of the Company’s interest rate swap was determined primarily based on quoted market prices. The Company has no long-term debt maturing until 2005. The following table shows the Company’s long-term debt maturities and the weighted-average interest rates by maturity date.

(Dollars in millions)	2005	Thereafter	Total	2003 Year-end Fair Value
Fixed rate debt				
Principal amount	$ 109.8	$ 348.6	$ 458.4	$ 497.8
Weighted-average interest rate	7.13%	6.55%	6.69%	---
Variable rate debt				
Principal amount (A)	---	$ 248.8	$ 248.8	$ 249.4
Weighted-average interest rate	---	2.01%	2.01%	---

(A) Amount includes an increase to the fair value of long-term debt of approximately $4.0 million due to Company’s interest rate swap.

Item 8. Financial Statements and Supplementary Data.

OKLAHOMA GAS AND ELECTRIC COMPANY
BALANCE SHEETS

December 31 *(In millions)*	**2003**	2002
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 4.0**	$ 0.3
Accounts receivable - customers, net	**123.1**	97.7
Accounts receivable - other, net	**9.9**	8.1
Advances to parent	**51.8**	---
Accrued unbilled revenues	**38.0**	28.2
Fuel inventories, at LIFO cost	**60.0**	65.4
Materials and supplies, at average cost	**41.4**	40.7
Accumulated deferred tax assets	**6.8**	7.5
Fuel clause under recoveries	**4.0**	14.7
Other	**6.2**	5.3
Total current assets	**345.2**	267.9
OTHER PROPERTY AND INVESTMENTS, at cost	**5.6**	8.1
PROPERTY, PLANT AND EQUIPMENT		
In service	**4,210.8**	4,098.2

Construction work in progress	**44.6**	38.7
Other	**1.0**	1.0
Total property, plant and equipment	**4,256.4**	4,137.9
Less accumulated depreciation	**2,006.0**	1,931.0
Net property, plant and equipment	**2,250.4**	2,206.9
DEFERRED CHARGES AND OTHER ASSETS		
Recoverable take or pay gas charges	**32.5**	32.5
Income taxes recoverable from customers, net	**31.6**	34.8
Intangible asset - unamortized prior service cost	**35.7**	37.8
Prepaid benefit obligation	**37.5**	29.6
Price risk management	**4.0**	7.5
Other	**32.7**	34.8
Total deferred charges and other assets	**174.0**	177.0
TOTAL ASSETS	**$2,775.2**	$2,659.9

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

OKLAHOMA GAS AND ELECTRIC COMPANY
BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2003**	2002
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 50.0**	$ ---
Accounts payable - affiliates	**40.9**	26.1
Accounts payable - other	**57.7**	63.2
Advances from parent	**---**	101.1
Customers' deposits	**35.8**	33.0
Accrued taxes	**20.6**	20.3
Accrued interest	**12.8**	13.9
Tax collections payable	**7.9**	6.7
Accrued vacation	**11.6**	11.6
Fuel clause over recoveries	**32.4**	---
Other	**15.3**	10.4
Total current liabilities	**285.0**	286.3
LONG-TERM DEBT		
Long-term debt	**707.2**	710.5
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**134.8**	148.6
Accumulated deferred income taxes	**535.9**	421.5
Accumulated deferred investment tax credits	**42.0**	47.1
Accrued removal obligations, net	**116.3**	109.3
Provision for payments of take or pay gas	**32.5**	32.5
Other	**1.6**	---
Total deferred credits and other liabilities	**863.1**	759.0
STOCKHOLDERS' EQUITY		

Common stockholders' equity	**512.4**	512.4
Retained earnings	**460.9**	455.2
Accumulated other comprehensive loss, net of tax	**(53.4)**	(63.5)
Total stockholders' equity	**919.9**	904.1
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$2,775.2**	$2,659.9

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

OKLAHOMA GAS AND ELECTRIC COMPANY
STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*		**2003**	2002
STOCKHOLDERS' EQUITY			
Common stock, par value $2.50 per share; authorized 100.0 shares; and outstanding 40.4 shares		**$ 100.9**	$ 100.9
Premium on capital stock		**411.5**	411.5
Retained earnings		**460.9**	455.2
Accumulated other comprehensive loss, net of tax		**(53.4)**	(63.5)
Total stockholders' equity		**919.9**	904.1
LONG-TERM DEBT			
SERIES	DATE DUE		
Senior Notes-			
7.125 %	Senior Notes, Series Due October 15, 2005	**110.0**	110.0
6.500 %	Senior Notes, Series Due July 15, 2017	**125.0**	125.0
Variable %	Senior Notes, Series Due October 15, 2025	**114.0**	117.5
6.650 %	Senior Notes, Series Due July 15, 2027	**125.0**	125.0
6.500 %	Senior Notes, Series Due April 15, 2028	**100.0**	100.0
Other bonds-			
Variable %	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
Variable %	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
Variable %	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0
Unamortized premium and discount, net		**(2.2)**	(2.4)
Total long-term debt		**707.2**	710.5
Total Capitalization		**$1,627.1**	$1,614.6

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

OKLAHOMA GAS AND ELECTRIC COMPANY
STATEMENTS OF INCOME

Year ended December 31 *(In millions)*	**2003**	2002	2001
OPERATING REVENUES	**$1,517.1**	$1,388.0	$1,456.8
COST OF GOODS SOLD	**837.4**	695.8	766.5
Gross margin on revenues	**679.7**	692.2	690.3
Other operation and maintenance	**294.8**	282.9	287.3
Depreciation	**121.8**	123.1	119.8

Taxes other than income	**46.9**	47.1	46.6
OPERATING INCOME	**216.2**	239.1	236.6
OTHER INCOME (EXPENSE)			
Other income	**0.8**	0.7	1.1
Other expense	**(3.2)**	(3.1)	(3.5)
Net other expense	**(2.4)**	(2.4)	(2.4)
INTEREST INCOME (EXPENSE)			
Interest income	**0.6**	1.2	2.4
Interest on long-term debt	**(36.9)**	(38.1)	(42.3)
Allowance for borrowed funds used during construction	**0.5**	0.9	0.7
Interest on short-term debt and other interest charges	**(2.4)**	(3.0)	(4.4)
Net interest expense	**(38.2)**	(39.0)	(43.6)
INCOME BEFORE TAXES	**175.6**	197.7	190.6
INCOME TAX EXPENSE	**60.2**	71.6	69.4
NET INCOME	**$ 115.4**	$ 126.1	$ 121.2

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

OKLAHOMA GAS AND ELECTRIC COMPANY
STATEMENTS OF RETAINED EARNINGS

Year ended December 31 *(In millions)*	**2003**	2002	2001
BALANCE AT BEGINNING OF PERIOD	**$ 455.2**	$ 433.1	$ 415.5
ADD: Net income	**115.4**	126.1	121.2
Total	**570.6**	559.2	536.7
DEDUCT: Dividends declared on common stock	**109.7**	104.0	103.6
BALANCE AT END OF PERIOD	**$ 460.9**	$ 455.2	$ 433.1

OKLAHOMA GAS AND ELECTRIC COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(In millions)*	**2003**	2002	2001
Net income	**$ 115.4**	$ 126.1	$ 121.2
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment [$16.5, ($71.0) and			

($32.5) pre-tax, respectively]	**10.1**	(43.6)	(19.9)
Total comprehensive income	**$ 125.5**	$ 82.5	$ 101.3

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

OKLAHOMA GAS AND ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS

Year ended December 31 *(In millions)*	**2003**	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 115.4**	$ 126.1	$ 121.2
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation	**121.8**	123.1	119.8
Deferred income taxes and investment tax credits, net	**107.6**	8.4	(0.2)
Other assets	**(3.9)**	(32.8)	(19.1)
Other liabilities	**(3.2)**	0.1	(4.7)
Change in certain current assets and liabilities			
Accounts receivable - customers, net	**(25.3)**	7.0	31.1
Accounts receivable - other, net	**(1.8)**	3.8	2.0
Accrued unbilled revenues	**(9.8)**	7.4	13.4
Fuel, materials and supplies inventories	**4.7**	(18.6)	20.8
Fuel clause under recoveries	**10.7**	(14.7)	35.4
Other current assets	**(1.1)**	(0.5)	(4.1)
Accounts payable	**(5.4)**	5.6	(41.3)
Accounts payable - affiliates	**11.9**	0.1	(25.4)
Customers' deposits	**2.7**	4.6	5.8
Accrued taxes	**0.3**	0.1	0.3
Accrued interest	**(1.0)**	(0.6)	(0.1)
Fuel clause over recoveries	**32.4**	(23.4)	23.4
Other current liabilities	**6.2**	5.6	(3.2)
Net Cash Provided from Operating Activities	**362.2**	201.3	275.1
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	**(148.7)**	(198.7)	(132.3)
Net Cash Used in Investing Activities	**(148.7)**	(198.7)	(132.3)
CASH FLOWS FROM FINANCING ACTIVITIES			
(Decrease) increase in short-term debt, net	**(102.8)**	101.1	(39.2)
Dividends paid on common stock	**(107.0)**	(103.8)	(103.6)
Net Cash Used in Financing Activities	**(209.8)**	(2.7)	(142.8)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**3.7**	(0.1)	---
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**0.3**	0.4	0.4
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 4.0**	$ 0.3	$ 0.4

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

OKLAHOMA GAS AND ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

Oklahoma Gas and Electric Company (the "Company") generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas and is subject to regulation by 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 is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. The Company sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

Accounting Records

The accounting records of the Company are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the 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 the expected recovery from customers in future rates. Likewise, certain credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment. At December 31, 2003 and 2002, regulatory assets (excluding recoverable take or pay gas charges) of approximately $61.7 million and $78.6 million, respectively, are being amortized and reflected in rates charged to customers over periods of up to 20 years. Recoverable take or pay gas charges are not reflected in rates charged to customers. See Note 11 for a further discussion. At December 31, 2003 and 2002, regulatory liabilities (excluding fuel clause over recoveries) of approximately $116.3 million and $109.3 million, respectively, have been reclassified from Accumulated Depreciation in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations."

The Company initially records certain costs: (i) that are probable of future recovery as a deferred charge until such time as the cost is approved by a regulatory authority, then the cost is reclassified as a regulatory asset; and (ii) that are probable of future liability as a deferred credit until such time as the amount is approved by a regulatory authority, then the amount is reclassified as a regulatory liability.

The following table is a summary of the Company's regulatory assets and liabilities at December 31:

(In millions)	**2003**	2002
Regulatory Assets		
Recoverable take or pay gas charges	**$ 32.5**	$ 32.5
Income taxes recoverable from customers, net	**31.6**	34.8
Unamortized loss on reacquired debt	**22.1**	23.3
Fuel clause under recoveries	**4.0**	14.7
January 2002 ice storm	**3.6**	5.4
Miscellaneous	**0.4**	0.4
Total Regulatory Assets	**$ 94.2**	$ 111.1
Regulatory Liabilities		
Accrued removal obligations, net	**$ 116.3**	$ 109.3
Fuel clause over recoveries	**32.4**	---
Total Regulatory Liabilities	**$ 148.7**	$ 109.3

Recoverable take or pay gas charges represent outstanding prepayments of gas related to a reserve for litigation that the Company is currently involved in which the Company expects full recovery through its regulatory approved fuel adjustment clause. See Note 11 for a further discussion.

Income taxes recoverable from customers represent income tax benefits previously used to reduce the Company's revenues. These amounts are being recovered in rates as the temporary differences that generated the income tax benefit turn around. The provisions of SFAS No. 71 allowed the Company to treat these amounts as regulatory assets and liabilities and they are being amortized over the estimated remaining life of the assets to which they relate. The income tax related regulatory assets and liabilities are netted on the Company's Balance Sheets in the line item, "Income Taxes Recoverable from Customers, Net."

Fuel Clause Under Recoveries are due to under recoveries from the Company's customers as the Company's cost of fuel exceeded the amount billed to its customers. Fuel Clause Over Recoveries are due to over recoveries from the Company's customers as the amount billed to its customers exceeded the Company's cost of fuel. The Company's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result the Company under recovers fuel cost in periods of rising prices above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses allow the Company to amortize under or over recovery.

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations. In accordance with SFAS No. 143, the Company was required to reclassify the accrued removal obligations, which had previously been recorded as a liability in Accumulated Depreciation, to a regulatory liability. See Note 2 for a further discussion.

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is reduced or written off, as appropriate.

If the Company were required to discontinue the application of SFAS No. 71 for some or all of its operations, it could result in writing off the related regulatory assets; the financial effects of which could be significant.

Use of Estimates

In preparing the 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. Changes to these assumptions and estimates could have a material effect on the Company's financial statements. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, contingency reserves, accrued removal obligations, regulatory assets and liabilities, unbilled revenue, the allowance for uncollectible accounts receivable and fair value hedging policies.

Cash and Cash Equivalents

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

The Company's cash management program utilizes controlled disbursement banking arrangements. Outstanding checks in excess of cash balances were approximately $19.0 million and $19.6 million at December 31, 2003 and 2002, 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.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the original due date The allowance for uncollectible accounts receivable is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. The allowance for uncollectible accounts receivable was approximately $2.6 million and $4.7 million at December 31, 2003 and 2002, respectively.

New business customers are required to provide a security deposit in the form of a case, bond, or irrevocable letter of credit which is refunded when the account is closed. New residential customers, whose outside credit scores indicate risk, are required to provide a security deposit which is refunded after 12 months of good payment history per the regulatory rules. The

payment behavior of all existing customers is monitored and if the payment behavior indicates sufficient risk per the regulatory rules, customers will be required to provide a security deposit.

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 $24.9 million and $7.0 million for 2003 and 2002, respectively, based on the average cost of fuel purchased. The amount of fuel inventory was approximately $60.0 million and $65.4 million at December 31, 2003 and 2002, respectively.

Property, Plant and Equipment

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

The Company's property, plant and equipment are divided into the following major classes at December 31, 2003 and 2002, respectively.

December 31 *(In millions)*	**2003**	2002

Distribution assets	**$ 1,834.7**	$ 1,749.6
Electric generation assets	**1,614.4**	1,609.5
Transmission assets	**536.9**	520.7
Intangible plant	**5.3**	4.8
Other property and equipment	**265.1**	253.3
Total property, plant and equipment	**$ 4,256.4**	$ 4,137.9

Depreciation

The provision for depreciation, which was approximately 2.9 percent of the average depreciable utility plant for 2003 and approximately 3.1 percent of the average depreciable utility plant for 2002, 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

AFUDC is calculated according to the FERC pronouncements for the imputed cost of equity and borrowed funds. AFUDC, a non-cash item, is reflected as a credit in the accompanying Statements of Income and as a charge to Construction Work in Progress in the accompanying Balance Sheets. AFUDC rates, compounded semi-annually, were 1.67 percent, 2.40 percent and 4.87 percent for the years 2003, 2002 and 2001, respectively.

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 for a minimum of $1,500 to a maximum of $13,000 with a term of six months to 84 months. The finance rate is based upon market rates and is reviewed and updated periodically. The interest rates were 11.55 percent and 10.99 percent at December 31, 2003 and 2002, respectively.

The Company's heat pump loan balance was approximately $1.4 million and $0.5 million at December 31, 2003 and 2002, respectively and is included in Accounts Receivable – Customers, Net in the accompanying Balance Sheet.

Revenue Recognition

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

Automatic Fuel Adjustment Clauses

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

Accrued Vacation

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

Accumulated Other Comprehensive Loss

Accumulated Other Comprehensive Loss includes approximately a $53.4 million after tax loss ($87.1 million pre-tax) and approximately a $63.5 million after tax loss ($103.5 million pre-tax), respectively, at December 31, 2003 and 2002 related to a minimum pension liability adjustment.

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 $84.4 million, $95.2 million and $85.5 million during 2003, 2002 and 2001, respectively. Energy Corp. allocates operating costs to its affiliates based on several factors. Operating costs directly related to specific affiliates are assigned to those affiliates. Where more than one affiliate benefits from certain expenditures, the costs are shared between those affiliates receiving the benefits. Operating costs incurred for the benefit of all affiliates are allocated among the affiliates, based primarily upon head-count, occupancy, usage or the "Distragas" method. The Distragas method is a three-factor formula that uses an equal weighting of payroll, operating income and assets. The Company believes this method provides a reasonable basis for allocating common expenses.

In 2003, 2002 and 2001, the Company paid its affiliate, Enogex Inc. and subsidiaries ("Enogex"), approximately $33.5 million, $33.6 million and $36.3 million, respectively, for transporting gas to the Company's natural gas-fired generating facilities. In 2003 and 2002, the Company paid Enogex approximately $11.2 million and $3.3 million, respectively, for natural gas storage services. Enogex did not provide storage services to the Company during 2001. In 2003, 2002 and 2001, the Company also recorded natural gas purchases from Enogex of approximately $20.8 million, $13.9 million and $4.8 million, respectively. Approximately $1.7 million was recorded at December 31, 2002 and is included in Accounts Payable – Affiliates in the accompanying Balance Sheets for these activities. There were no amounts recorded for these activities at December 31, 2003.

In 2003, 2002 and 2001, the Company recorded interest income of approximately $0.1 million, $0.3 million and $0.3 million, respectively, from Energy Corp. for advances made by the Company to Energy Corp.

In 2003, 2002 and 2001, the Company recorded interest expense of approximately $1.1 million, $0.7 million and $2.6 million, respectively, to Energy Corp. for advances made by

Energy Corp. to the Company. The interest rate charged on advances to the Company from Energy Corp. approximates Energy Corp.'s commercial paper rate.

In 2003, 2002 and 2001, the Company paid approximately $107.0 million, $103.8 million and $103.6 million, respectively, in dividends to Energy Corp.

Reclassifications

Certain prior year amounts have been reclassified on the financial statements to conform to the 2003 presentation.

2. Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. The scope of SFAS No. 143 includes the Company's accrued plant removal costs for generation, transmission and distribution assets and requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of the fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of the fair value can be made. Asset retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. The recognition of an asset retirement obligation is capitalized as part of the carrying amount of the long-lived asset. Asset retirement obligations represent future liabilities and, as a result, accretion expense is accrued on this liability until such time as the obligation is satisfied. Adoption of SFAS No. 143 was required for financial statements issued for fiscal years beginning after June 15, 2002. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its financial position or results of operations.

In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to retire certain assets. As the Company currently has no plans to retire any of these assets and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will monitor these assets and record a liability when a reasonable estimate of the fair value can be made.

SFAS No. 143 also requires that, if the conditions of SFAS No. 71 are met, a regulatory asset or liability should be recorded to recognize differences between asset retirement costs recorded under SFAS No. 143 and legal or other asset retirement costs recognized for ratemaking purposes. Upon the application of SFAS No. 143, all rate regulated entities that are subject to the statement requirements will be required to quantify the amount of previously accumulated asset retirement costs and reclassify those differences as regulatory assets or liabilities. At December 31, 2002, approximately $109.3 million had been previously recovered from ratepayers and recorded as a liability in Accumulated Depreciation related to estimated asset

retirement obligations. This balance was reclassified as a regulatory liability on the December 31, 2002 Balance Sheet. At December 31, 2003, the regulatory liability for accrued removal obligations, net was approximately $116.3 million.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 addresses financial accounting and reporting for costs associated with exit and disposal activities and supersedes Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF 94-3. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. Adoption of

SFAS No. 146 was required for exit and disposal activities initiated after December 31, 2002. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its financial position or results of operations.

In December 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." Interpretation No. 45 requires that at the time a company issues a guarantee, the company must recognize an initial liability for the fair value, or market value, of the obligations it assumes under that guarantee. Interpretation No. 45 is applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The Company adopted this new interpretation effective January 1, 2003 and the adoption of this new interpretation did not have a material impact on its financial position or results of operations.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51." Interpretation No. 46 requires the consolidation of entities in which an enterprise absorbs a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity. Currently, entities are generally consolidated by an enterprise when it has a controlling financial interest through ownership of a majority voting interest in the entity.

In October 2003, the FASB issued Interpretation No. 46-6, "Effective Date of FASB Interpretation No. 46, Consolidation of Variable Interest Entities," in which the FASB agreed to defer, for public companies, the required effective dates to implement Interpretation No. 46 for interests held in a variable interest entity ("VIE") or potential VIE that was created before February 1, 2003. For calendar year-end public companies, the deferral effectively moved the required effective date from the third quarter to the fourth quarter of 2003.

As a result of Interpretation No. 46-6, a public entity need not apply the provisions of Interpretation No. 46 to an interest held in a VIE or potential VIE until the end of the first interim or annual period ending after December 15, 2003, if the VIE was created before February 1, 2003 and the public entity has not issued financial statements reporting that VIE in accordance with Interpretation No. 46, other than in the disclosures required by Interpretation No. 46. Interpretation No. 46 may be applied prospectively with a cumulative-effect adjustment as of the

date on which it is first applied or by restating previously issued financial statements for one or more years with a cumulative-effect adjustment as of the beginning of the first year restated. The Company adopted this new interpretation effective December 31, 2003 and the adoption of this new interpretation did not have a material impact on its financial position or results of operations.

In April 2003, the FASB issued SFAS No. 149, "Amendments of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain instruments embedded in other contracts and for hedging activities under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. This statement requires that contracts with comparable characteristics be accounted for similarly. In particular, this statement clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative, clarifies when a derivative contains a financing component, amends the definition of an underlying hedged risk to conform to language used in Interpretation No. 45 and amends certain other existing pronouncements. This statement, the provisions of which are to be applied prospectively, is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The Company adopted this new standard effective July 1, 2003 and the adoption of this new standard did not have a material impact on its financial position or results of operations.

In December 2003, the FASB issued SFAS No. 132 (Revised), "Employers' Disclosures about Pensions and Other Postretirement Benefits, an amendment of FASB Statements No. 87, 88 and 106." This Statement revised employers' disclosures about pension plans and other postretirement benefits. It does not change the measurement or recognition of those plans required by FASB Statements No. 87, "Employers' Accounting for Pensions," No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," and No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." This Statement requires additional disclosures to those in the original Statement 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits," for defined benefit pension plans and other defined benefit postretirement plans. Additional disclosures include information describing the types of plan assets, investment strategy, measurement date, plan obligations, cash flows and the components of net periodic benefit cost recognized during interim periods. Adoption of the provisions of this statement, except the provisions related to foreign plans and estimated future benefit payments, is required for financial statements issued for fiscal years ending after December 15, 2003. Adoption of the interim provisions of this statement is required for interim periods beginning after December 15, 2003. Adoption of the provisions of this statement related to foreign plans and estimated future benefit payments is required for financial statements issued for fiscal years ending after June 15, 2004. The Company adopted this new standard effective December 31, 2003 and the adoption of this new standard did not have a material impact on its financial position or results of operations.

3. Price Risk Management Assets and Liabilities

The Company periodically utilizes derivative contracts to reduce exposure to adverse interest rate fluctuations. During 2003 and 2002, the Company's use of price risk management instruments involved the use of an interest rate swap agreement. This agreement involved the

exchange of fixed price or rate payments over the life of the instrument without an exchange of the underlying principal amount.

In accordance with SFAS No. 133, the Company recognizes all of its derivative instruments as Price Risk Management assets or liabilities in the Balance Sheet at fair value with such amounts classified as current or long-term based on their anticipated settlement. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item attributable to the hedged risk are recognized in the same line item associated with the hedged item in current earnings during the period of the change in fair values. For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other

Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value is recognized currently in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and hedged item during the period of hedge designation. Forecasted transactions designated as the hedged item in a cash flow hedge are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings. Any amounts recorded in Accumulated Other Comprehensive Income will remain in other comprehensive income until such time the forecasted transaction is deemed probable not to occur. The Company's interest rate swap agreement has been designated as a fair value hedge and qualified for the shortcut method prescribed by SFAS No. 133. Under the shortcut method, the Company assumes that the hedged item's change in fair value is exactly as much as the derivative's change in fair value.

4. Supplemental Cash Flow Information

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

Year ended December 31 *(In millions)*	**2003**	2002	2001
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $0.5, $0.9, $0.7)	**$ 35.9**	$ 35.6	$ 44.7
Income taxes (net of income tax refunds)	**(39.8)**	61.9	75.2
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Change in fair value of long-term debt due to interest rate swap	**$ (3.5)**	$ 9.9	$ (2.4)

5. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2003**	2002	2001
Provision (Benefit) for Current Income Taxes			
Federal	**$ (42.0)**	$ 55.9	$ 59.7
State	**(4.7)**	7.7	9.9
Total Provision (Benefit) for Current Income Taxes	**(46.7)**	63.6	69.6
Provision for Deferred Income Taxes, net			
Federal	**99.4**	11.0	3.9
State	**13.4**	2.6	1.1
Total Provision for Deferred Income Taxes, net	**112.8**	13.6	5.0
Deferred Investment Tax Credits, net	**(5.2)**	(5.2)	(5.2)
Income Taxes Relating to Other Income and Deductions	**(0.7)**	(0.4)	--
Total Income Tax Expense	**$ 60.2**	$ 71.6	$ 69.4

In connection with the filing in the third quarter of 2003 of Energy Corp.'s consolidated income tax returns for 2002, Energy Corp. elected to change its tax method of accounting related to the capitalization of costs for self-constructed assets to another method prescribed in the Treasury regulations. The accounting method change is for income tax purposes only. For financial accounting purposes, the only change would be recognition of the impact of the cash flow generated by accelerating income tax deductions. This would be reflected in the financial statements as a switch from current income taxes payable to deferred income taxes payable. This tax accounting method change resulted in a one-time catch-up deduction for costs previously capitalized under the prior method, resulting in a consolidated tax net operating loss for 2002. This tax net operating loss eliminated Energy Corp.'s current federal and state income tax liability for 2002 and all estimated payments made for 2002 have been or will be refunded. Energy Corp. received federal and state income tax refunds of approximately $50.0 million during 2003 related to this tax accounting method change.

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

Year ended December 31	**2003**	2002	2001
Statutory federal tax rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	**3.6**	3.4	3.7
Tax credits, net	**(2.9)**	(2.6)	(2.7)
Other, net	**(1.4)**	0.4	0.4
Effective income tax rate as reported	**34.3%**	36.2%	36.4%

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 Taxes at December 31, 2003 and 2002 respectively, are as follows:

(In millions)	**2003**	2002
Current Accumulated Deferred Tax Assets		
Accrued vacation	**$ 3.9**	$ 4.2
Uncollectible accounts	**1.1**	1.9
Other	**1.8**	1.4
Total Current Accumulated Deferred Tax Assets	**$ 6.8**	$ 7.5
Non-Current Accumulated Deferred Tax Liabilities		
Accelerated depreciation and other property related differences	**$ 501.7**	$ 400.7
Allowance for funds used during construction	**33.1**	35.6
Income taxes refundable to customers	**22.0**	24.4
Bond redemption-unamortized costs	**7.7**	8.1
Total Non-Current Accumulated Deferred Tax Liabilities	**564.5**	468.8
Non-Current Accumulated Deferred Tax Assets		
Deferred investment tax credits	**(12.1)**	(13.8)
Income taxes recoverable from customers	**(9.8)**	(10.9)
Postretirement medical and life insurance benefits	**(3.8)**	(1.0)
Company pension plan	**(0.9)**	(19.4)
Other	**(2.0)**	(2.2)
Total Non-Current Accumulated Deferred Tax Assets	**(28.6)**	(47.3)
Non-Current Accumulated Deferred Income Tax Liabilities, net	**$ 535.9**	$ 421.5

6. Common Stock and Cumulative Preferred Stock

There were no new shares of common stock issued during 2003, 2002 or 2001. The Company's Restated Certificate of Incorporation permits the issuance of a new series of preferred stock with dividends payable other than quarterly.

7. Stock Incentive Plan

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

In 2003, Energy Corp. adopted, and its shareowners approved, a new Stock Incentive Plan (the "2003 Plan" and together with the 1998 Plan, the "Plans"). The 2003 Plan replaced the 1998 Plan and no further awards will be granted under the 1998 Plan. As under the 1998 Plan, under

the 2003 Plan, registered stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees, including officers, directors and employees of the Company. Energy Corp. has authorized the issuance of up to 2,700,000 shares under the 2003 Plan.

Restricted Stock

During 2003 and 2002, no restricted stock was distributed under the Plans. Energy Corp. distributed 67,410 shares of restricted common stock under the 1998 Plan during 2001 with a grant date fair value of $21.87 per share. The restricted stock distributed vests at the end of three years. Each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to Energy Corp. or a subsidiary for any reason other than death, disability or retirement. Awards of restricted stock are subject to an additional condition with all or a portion of the shares of restricted stock being subject to forfeiture based on Energy Corp.'s return on equity compared to a peer group of companies during the three-year restriction period.

Performance Units

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

Stock Options

Options granted under the Plans vest in one-third annual installments beginning one year from the date of grant and have a contractual life of 10 years. Energy Corp. has had no expirations of options. Stock option transactions related to the Plans are summarized in the following table:

	2003		2002		2001	
	Number of Options	**Weighted Average Price**	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Options Outstanding at beginning of year	**349,800**	**$23.9551**	258,300	$24.5569	214,200	$25.0406
Granted	**117,000**	**16.6850**	92,100	22.2300	50,600	22.5000
Exercised	**(27,033)**	**18.6791**	(600)	18.2500	(333)	18.2500
Cancelled	**(8,900)**	**25.3287**	---	---	(6,167)	24.8213
Options Outstanding at end of year	**430,867**	**$22.2836**	349,800	$23.9551	258,300	$24.5569
Options Exercisable at end of year	**237,321**	**$25.0437**	213,054	$24.2924	155,358	$25.8549

The fair value of each option grant under the Plans for the years ended December 31, 2003, 2002 and 2001, are estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants in 2003, 2002 and 2001:

	2003	2002	2001
Expected dividend yield	**6.30%**	6.05%	5.70%
Expected price volatility	**22.06%**	22.95%	24.03%
Risk-free interest rate	**3.80%**	4.90%	5.17%
Expected life of options (in years)	**7**	7	7
Weighted-average fair value of options granted	**$ 1.85**	$ 3.10	$ 3.61

The following table provides additional information about stock options outstanding at December 31, 2003:

		Options Outstanding		Options Exercisable	
Range of Exercise Prices	Weighted-Average Remaining Contractual Life	Number Outstanding	Weighted-Average Exercise Price	Number Outstanding	Weighted-Average Exercise Price
$16.69 - $22.70	8.04 years	277,167	$ 19.6199	89,455	$ 21.1280

$25.75 - $28.75	4.18 years	153,700	$ 27.0870	153,700	$ 27.0870

8. Long-Term Debt

A summary of the Company's long-term debt is included in the accompanying Statements of Capitalization. The Company has four series of long-term debt with optional redemption provisions which allow the holders to request repayment of the long-term debt at various dates prior to the maturity. The debt series which are redeemable at the option of the holder during the next 12 months are as follows:

SERIES	DATE DUE	AMOUNT
6.500 %	Senior Notes, Series Due July 15, 2017	**$ 125.0**
Variable %	Garfield Industrial Authority, January 1, 2025	**47.0**
Variable %	Muskogee Industrial Authority, January 1, 2025	**32.4**
Variable %	Muskogee Industrial Authority, June 1, 2027	**56.0**
Total		**$ 260.4**

The 6.500 percent Senior Notes ("Senior Notes") will be repayable on July 15, 2004, at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to July 15, 2004. In order for a Senior Note to be repaid, the Company must receive at the principal corporate trust office of the Senior Note Trustee during the period from and including May 15, 2004 to and including the close of business on June 15, 2004, a Senior Note with the form entitled "Option to Elect Repayment" on these Senior Notes or other documentation with this information. The repayment option may be exercised by the holder of a Senior Note for less than the entire principal amount of the Senior Note, provided the principal amount is in denominations of $1,000. If the Senior Note holders elect repayment options prior to the maturity, the Company has sufficient liquidity but would seek to refinance these obligations in the capital markets. Such refinancing may incur higher annual interest charges. However, the Company does not believe there is a high probability that repayment of the Senior Notes will be accelerated due to the current and anticipated interest rate environment.

All of the variable rate industrial authority bonds ("Bonds") are subject to tender at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid

interest to the date of purchase. The bond holders, on any business day, can request repayment of the Bond by delivering an irrevocable notice to the tender agent stating the principal amount of the Bond, payment instructions for the purchase price and the business day the Bond is to be purchased. The repayment option may only be exercised by the holder of a Bond for the entire principal amount. A third party remarketing agent for the Bonds will attempt to remarket any Bonds tendered for purchase. If the remarketing agent is unable to remarket any such Bonds, the Company is obligated to repurchase such unremarketed Bonds. The Company has sufficient liquidity to meet these obligations. However, the Company does not believe there is a high probability that repayment of the Bonds will be accelerated due to the current and anticipated interest rate environment.

Maturities of the Company's long-term debt during the next five years consist of $110.0 million in 2005.

The Company has previously incurred costs related to debt refinancings. Unamortized debt expense and unamortized loss on reacquired debt are classified as Deferred Charges and Other Assets – Other and unamortized premium and discount on long-term debt is classified as Long-Term Debt, respectively, in the accompanying Balance Sheets and are being amortized over the life of the respective debt. Also, at December 31, 2003, the Company is in compliance with all of its debt agreements.

Interest Rate Swap Agreement

At December 31, 2003 and 2002, the Company had one outstanding interest rate swap agreement effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate. The objective of this interest rate swap was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. This interest rate swap qualified as a fair value hedge under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At December 31, 2003 and 2002, the fair values pursuant to the interest rate swap were approximately $4.0 million and $7.5 million, respectively, and are classified as Deferred Charges and Other Assets – Price Risk Management in the accompanying Balance Sheets. A corresponding net increase of approximately $4.0 million and $7.5 million was reflected in Long-Term Debt at December 31, 2003 and 2002, respectively, as these fair value hedges were effective at December 31, 2003 and 2002.

9. Short-Term Debt

At December 31, 2003, the Company had approximately $50.0 million in short-term debt outstanding and approximately $51.8 million in short-term debt to Energy Corp. outstanding. At December 31, 2002, the Company had approximately $101.1 million in short-term debt from Energy Corp. outstanding. The Company generally uses short-term borrowings from Energy Corp. to meet working capital requirements. As indicated below, the Company also has in place a $100 million line of credit with a bank. The following table shows Energy Corp.'s and the

Company's lines of credit in place and available cash at December 31, 2003. Energy Corp's short-term borrowings are expected to consist of a combination of bank borrowings and commercial paper.

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

Entity	Amount Available	Amount Outstanding	Maturity
Energy Corp. (A)	$ 15.0	$ ---	April 6, 2004
The Company	100.0	---	June 26, 2004
Energy Corp. (A)	300.0	---	December 9, 2004
Total	415.0	---	
Cash	245.6	N/A	N/A
Total	$ 660.6	$ ---	

(A) The lines of credit at Energy Corp. are used to back up the Company's commercial paper borrowings, which were approximately $202.5 million at December 31, 2003. As shown in the table above, on December 11, 2003, the Company renewed its credit facility of $300.0 million maturing on December 9, 2004. This agreement has a one-year term.

Energy Corp.'s ability to access the commercial paper market could be adversely impacted by a commercial paper ratings downgrade. The lines of credit contain rating grids that require annual fees and borrowing rates to increase if Energy Corp. suffers an adverse ratings impact. The impact of additional downgrades of Energy Corp.'s rating 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 rating changes.

The Company must obtain regulatory approval from the FERC in order to borrow on a short-term basis. The Company has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time.

10. Retirement Plans and Postretirement Benefit Plans

Defined Benefit Pension Plan

All eligible employees of the Company are covered by a non-contributory defined benefit pension plan sponsored by Energy Corp. In early 2000, the Board of Energy Corp. approved significant changes to the pension plan. Prior to these changes, benefits were based primarily on years of service and the average of the five highest consecutive years of compensation during an employee's last 10 years prior to 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 Energy Corp. 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 Energy Corp'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. During 2003 and 2002, Energy Corp. made contributions of approximately $50.0 million and $48.8 million, respectively, of which approximately $38.8 million and $37.3 million, respectively, were allocated to the Company 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 2004, Energy Corp. plans to contribute approximately $56.0 million to the plan, of which approximately $43.5 million is the Company's portion. The expected contribution to the pension plan, anticipated to be in the form of cash, is a discretionary contribution and is not required to satisfy the minimum regulatory funding requirements specified by the Employee Retirement Income Security Act of 1974 ("ERISA").

During 2003 and 2002, Energy Corp. made contributions to the pension plan that exceeded amounts previously recognized as net periodic pension expense and recorded a prepaid benefit obligation at December 31, 2003 and 2002 of approximately $55.7 million and $44.9 million, respectively, of which approximately $37.5 million and $29.6 million, respectively, were allocated to the Company. At December 31, 2003 and 2002, Energy Corp.'s projected pension benefit obligation exceeded the fair value of pension plan assets by approximately $131.8 million and $156.7 million, respectively, of which approximately $117.6 million and $137.8 million, respectively were allocated to the Company. 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 $137.6 million and $163.9 million, respectively, for Energy Corp., of which approximately $122.8 million and $141.3 million, respectively, were allocated to the Company at December 31, 2003 and 2002. 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 2003 or 2002 and did not require a usage of cash and is therefore excluded from the accompanying 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 investments in mutual funds, U.S. Government securities, listed common stocks and corporate debt. The following table shows, by major category, the percentage of the fair value of the plan assets held at December 31, 2003 and 2002:

	2003	2002
Equity securities	**61%**	60%
Debt securities	**38%**	39%
Other securities	**1%**	1%
Total	**100%**	100%

Investment Policies and Strategies

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

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

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

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

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

Asset Class	Comparative Benchmark(s)
Fixed Income	Lehman Aggregate Index
Value Equity	Russell 1000 Value Index- Short-term
	S&P 500 Index - Long-term
Growth Equity	Russell 1000 Growth Index- Short-term
	S&P 500 Index - Long-term
Mid-Cap Equity	Russell Midcap Index

Small-Cap Equity	Russell 2000 Index
Global Equity	Far East Index

The fixed income manager is expected to use discretion over the asset mix of the master trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies, or its instrumentalities (which have no limits) is limited to five percent of the fixed income portfolio as measured by market value. Exposure to any single non-government issue is limited to three percent. At least 80 percent of the invested assets must possess an investment grade rating at or above Baa3 or BBB- by Moody's Investors Service ("Moody's"), Standard & Poor's Ratings Services ("Standard & Poor's"), Fitch Ratings ("Fitch") or Duff & Phelps LLC. The manager may invest up to 10 percent of the portfolio's market value in cash equivalents (securities with less than six months to maturity). The portfolio may invest up to 10 percent of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. No mortgage derivatives or structured notes are permitted. The purchase of any of Energy Corp.'s or its subsidiaries equity, debt or other securities is prohibited.

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell Midcap, small dividend yield, return on equity at or near the Russell Midcap and earnings per share growth rate at or near the Russell Midcap. The small-capitalization equity manager will purchase shares of companies with market capitalizations lower that the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and earnings per share growth rate at or near the Russell 2000. The global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall master trust across the global equity markets. The managers are required to operate under certain restrictions including: regional constraints, diversification requirements and percentage of U.S. securities. The Morgan Stanley Capital International Europe, Australia and the Far East Index ("EAFE") are the benchmark for comparative performance purposes. The EAFE Index is a market value weighted index comprised of over 1,000 companies traded on the stock markets of Europe, Australia, New Zealand and the Far East. All of the equities which are purchased for the fund are thoroughly researched. Only companies with a market capitalization in excess of $100 million are

allowable. No more than five percent of the portfolio can be invested in any one stock at the time of purchase. All securities are freely traded on a recognized stock exchange and there are no 144-A securities and no over-the-counter derivatives. The following investment categories are excluded: options, (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares). A minimum of 95 percent of the total assets must be allocated to the equity markets. Private placement or venture capital may not be purchased. All interest and dividend payments must be swept on a daily basis into a short-term money market or fund for re-deployment. The purchase of any of Energy Corp.'s or its subsidiaries equity, debt or other securities is prohibited. The purchase of equity or debt issues of the portfolio manager's organization is also prohibited.

Postretirement Benefit Plans

In addition to providing pension benefits, Energy Corp. 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 the cost-of-service in future ratemaking proceedings.

A reconciliation of the funded status of the plans and the amounts included in the accompanying Balance Sheets are as follows:

Projected Benefit Obligations

	Pension Plan		Postretirement Benefit Plans	
(In millions)	**2003**	2002	**2003**	2002
Beginning obligations	**$(373.9)**	$ (345.2)	**$ (160.9)**	$ (107.0)
Service cost	**(10.3)**	(9.1)	**(2.1)**	(1.9)
Interest cost	**(24.6)**	(24.5)	**(9.4)**	(8.5)
Participants' contributions	---	---	**(1.8)**	(1.1)
Plan changes	**(3.0)**	(0.1)	---	---
Actuarial gains (losses)	**(34.9)**	(41.0)	**7.8**	(51.7)
Benefits paid	**42.1**	45.3	**10.3**	9.3
Expenses	**0.6**	0.7	---	---
Ending obligations	**$ (404.0)**	$ (373.9)	**$ (156.1)**	$ (160.9)

Fair Value of Plans' Assets

	Pension Plan		Postretirement Benefit Plans	
(In millions)	**2003**	2002	**2003**	2002
Beginning fair value	**$ 236.1**	$ 259.6	**$ 44.6**	$ 51.1
Actual return on plans' assets	**54.2**	(14.8)	**9.5**	(6.5)
Employer contributions	**38.8**	37.3	**8.6**	8.2
Participants' contributions	---	---	**1.8**	1.1
Benefits paid	**(42.1)**	(45.3)	**(10.3)**	(9.3)
Expenses	**(0.6)**	(0.7)	---	---
Ending fair value	**$ 286.4**	$ 236.1	**$ 54.2**	$ 44.6

Net Periodic Benefit Cost

	Pension Plan			Postretirement Benefit Plans		
(In millions)	**2003**	2002	2001	**2003**	2002	2001
Service cost	**$ 10.3**	$ 9.1	$ 8.4	**$ 2.1**	$ 1.9	$ 1.4
Interest cost	**24.6**	24.5	25.8	**9.4**	8.5	7.4
Return on plan assets	**(19.9)**	(22.6)	(21.1)	**(5.2)**	(5.3)	(5.1)
Amortization of transition obligation	---	---	(1.1)	**2.5**	2.5	2.5
Amortization of net (gain) loss	**10.9**	3.7	0.4	**3.1**	0.5	(0.6)
Amortization of unrecognized prior service cost	**5.0**	4.8	4.7	**1.5**	1.5	1.5
Net periodic benefit cost	**$ 30.9**	$ 19.5	$ 17.1	**$ 13.4**	$ 9.6	$ 7.1

The capitalized portion of the net periodic pension benefit cost was approximately $5.7 million, $3.9 million and $3.4 million at December 31, 2003, 2002 and 2001, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $2.5 million, $1.9 million and $1.4 million at December 31, 2003, 2002 and 2001, respectively.

Funded Status of Plans

	Pension Plan		Postretirement Benefit Plans	
(In millions)	**2003**	2002	**2003**	2002
Funded status of the plans	**$ (117.6)**	$ (137.8)	**$ (101.9)**	$ (116.3)
Unrecognized net (gain) loss	**119.3**	129.6	**58.5**	73.7
Unrecognized prior service cost	**35.8**	37.8	**8.4**	9.9
Unrecognized transition obligation	---	---	**22.9**	25.4
Net amount recognized	**$ 37.5**	$ 29.6	**$ (12.1)**	$ (7.3)

Amounts recognized in the Balance Sheets consist of:

Pension Plan

(In millions)	2003	2002
Prepaid benefit obligation	**$ 37.5**	$ 29.6
Accrued pension and benefit obligations	**(122.8)**	(141.3)
Intangible asset - unamortized prior service cost	**35.7**	37.8
Accumulated deferred tax asset	**33.7**	40.0
Accumulated other comprehensive loss, net of tax	**53.4**	63.5
Net amount recognized	**$ 37.5**	$ 29.6

Rate Assumptions

	Pension Plan			Postretirement Benefit Plans		
	2003	2002	2001	**2003**	2002	2001
Discount rate	**6.25%**	6.75%	7.25%	**6.25%**	6.75%	7.25%
Rate of return on plans' assets	**8.75%**	9.00%	9.00%	**8.75%**	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	**11.00%**	12.00%	6.00%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2010**	2010	2006

N/A - not applicable

The overall expected rate of return on plan assets assumption was decreased from 9.00 percent in 2002 to 8.75 percent in 2003 in determining net periodic pension cost. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the pension plan. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans' current and expected asset allocation.

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE

(In millions)	2003	2002	2001
Effect on aggregate of the service and interest cost components	**$ 1.5**	$ 1.3	$ 1.0
Effect on accumulated postretirement benefit obligations	**19.2**	19.6	11.8

ONE-PERCENTAGE POINT DECREASE

(In millions)	2003	2002	2001
Effect on aggregate of the service and interest cost components	**$ 1.2**	$ 1.0	$ 0.8
Effect on accumulated postretirement benefit obligations	**15.7**	16.1	9.8

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Act"). The Act expanded Medicare to include, for the first time, coverage for prescription drugs. Energy Corp. sponsors retiree medical programs for certain of its locations and Energy Corp. expects that this legislation will eventually reduce its costs for some of these programs.

At this point, Energy Corp.'s investigation into its response to the legislation is preliminary, as we await guidance from various governmental and regulatory agencies concerning the requirements that must be met to obtain these cost reductions as well as the manner in which such savings should be measured. Based on this preliminary analysis, it appears that some of Energy Corp.'s retiree medical plans will need to be changed in order to qualify for beneficial treatment under the Act, while other plans can continue unchanged.

Because of various uncertainties related to Energy Corp.'s response to this legislation and the appropriate accounting methodology for this event, Energy Corp. has elected to defer financial recognition of this legislation until the FASB issues final accounting guidance. When issued, that final guidance could require Energy Corp. to change previously reported information. This deferral election is permitted under FASB Staff Position FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003."

Defined Contribution Plan

Energy Corp. provides a defined contribution savings plan. Each regular full-time employee of the Company or an affiliate is eligible to participate in the plan immediately. All other employees of the Company or an affiliate are eligible to become participants in the plan after completing one year of service as defined in the plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the plan, for that pay period. Contributions of the first six percent of compensation are called "Regular Contributions" and any contributions over six percent of compensation are called "Supplemental Contributions." The Company contributes to the Plan each pay period on behalf of each participant an amount equal to 50 percent of the participant's Regular Contributions for participants whose employment or re-employment date, as defined in the plan, occurred before February 1, 2000 and who have less than 20 years of service, as defined in the plan, and an amount equal to 75 percent of the participant's Regular Contributions for participants whose employment or re-employment date occurred before February 1, 2000 and who have 20 or more years of service. For participants whose employment or re-employment date occurred on or after February 1, 2000, the Company shall contribute 100 percent of the Regular Contributions deposited during such pay period by such participant. No Company contributions are made with respect to a participant's Supplemental Contributions or with respect to a participant's Regular Contributions effective July 1, 2000 based on overtime payments, pay-in-lieu of overtime for exempt personnel and special lump-sum recognition awards and effective September 20, 2000, for lump-sum merit awards included in compensation for determining the amount of participant contributions. The Company's contribution which is allocated for investment to the OGE Energy Corp. Common Stock Fund may be made in shares of Energy Corp.'s common stock or in cash which is used to invest in Energy Corp.'s common stock.

Deferred Compensation Plan

Energy Corp. provides a deferred compensation plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of Energy Corp. and to supplement such employees' defined contribution plan contributions.

Eligible employees who enroll in the Plan may elect to defer up to a maximum of 70 percent of base salary and 100 percent of bonus awards. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers; however, the Benefits Committee, appointed by the Benefits Oversight Committee (which consists of at least two members appointed by the Board of Directors) may, at its discretion, establish minimum amounts that must be deferred by anyone electing to participate in the plan. In addition, the Compensation Committee of the Board of Directors may authorize employer contributions to participants and the Chief Executive Officer of Energy Corp. (with Compensation Committee approval) is authorized to cause Energy Corp. to enter into "Deferred Compensation Award Agreements" with such participants. There were no employer contributions to the plan for the years ended December 31, 2003, 2002 or 2001.

11. Commitments and Contingencies

Capital Expenditures

The Company's capital expenditures are estimated at approximately: 2004 – $365.0 million, 2005 – $205.0 million and 2006 – $205.0 million.

Operating Lease Obligations

The Company has operating lease obligations expiring at various dates for railcar leases. Future minimum payments for noncancellable railcar leases are as follows:

(In millions)	2004	2005	2006	2007	2008	2009 and Beyond
Operating lease obligations						
Railcars	$ 5.4	$ 5.5	$ 5.4	$ 5.5	$ 5.4	$ 30.4

Payments for operating lease obligations were approximately $5.4 million, $5.4 million and $5.1 million in 2003, 2002 and 2001, respectively.

Railcar Leases

At December 31, 2003, the Company has noncancellable operating leases which have purchase options covering 1,479 coal hopper railcars to transport coal from Wyoming to the Company's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through the Company's tariffs and automatic fuel adjustment clauses. At the end of the lease term which is March 31, 2006, the Company has the option to purchase the railcars at a

stipulated fair market value. If the Company chooses not to purchase the railcars, the Company has a loss exposure up to approximately $9.0 million related to the fair market value of the railcars to the extent the fair market value is less than 80 percent of the lessor's cost of equipment. The Company is also required to maintain the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

Public Utility Regulatory Policy Act of 1978

The Company has entered into agreements with four qualifying cogeneration facilities having initial terms of three to 32 years. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978 ("PURPA"). Stated generally, PURPA and the regulations thereunder promulgated by the FERC require 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 2003, 2002 and 2001, the Company made total payments to cogenerators of approximately $203.0 million, $227.3 million and $222.5 million, respectively, of which approximately $164.7 million, $192.1 million and $190.7 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Statements of Income as Cost of Goods Sold. The future minimum capacity payments under the contracts are approximately: 2004 – $152.8 million, 2005 – $87.9 million, 2006 – $86.4 million, 2007 – $84.7 million and 2008 – $3.1 million.

Fuel Minimum Purchase Commitments

The Company purchased necessary fuel supplies of coal and natural gas for its generating units of approximately $157.3 million, $164.1 million and $120.0 million for the years ended December 31, 2003, 2002 and 2001, respectively. The Company has entered into purchase commitments of necessary fuel supplies of approximately: 2004 – $160.8 million, 2005 – $170.9 million, 2006 – $150.0 million, 2007 – $152.6 million, 2008 – $155.3 million and 2009 and Beyond – $152.4 million.

The Company acquires some of its natural gas for boiler fuel under a wellhead contract that contains provisions allowing the owner to require prepayments for gas if certain minimum quantities are not taken. At December 31, 2003 and 2002, outstanding prepayments for gas of approximately $32.5 million have been recorded in the Provision for Payments of Take or Pay Gas classified as Deferred Credits and Other Liabilities in the accompanying Balance Sheets. The outstanding prepayments of gas relate to a reserve for litigation that the Company is currently involved in. As the Company may be required to make these prepayments, offsetting amounts of approximately $32.5 million have been recorded at December 31, 2003 and 2002, respectively, in Recoverable Take or Pay Gas Charges classified as Deferred Charges and Other

Assets in the accompanying Balance Sheets as the Company expects full recovery through its regulatory approved fuel adjustment clause.

Natural Gas Units

The Company utilized a request for bid ("RFB") to acquire approximately 42 percent of its projected annual natural gas requirements through approximately April 2004. These contracts are tied to various gas price market indices and most will expire in April 2004. A significant portion of future gas requirements of the Company will be secured through a new multi-year RFB that was issued in February 2004 with deliveries to begin in April 2004. Additional gas requirements of the Company will be met with monthly and day-to-day purchases as required.

Natural Gas Measurement Cases

Grynberg – On June 15, 1999, the Company was served with plaintiff's complaint, which is a qui tam action under the False Claims Act in the United States District Court, State of Oklahoma by plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleging: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and British thermal unit ("Btu") content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees.

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

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

In October 2002, the Court granted the Department of Justice's motion to dismiss certain of Plaintiff's claims and issued an order dismissing Plaintiff's valuation claims against all defendants. Various procedural motions have been filed. Discovery is proceeding on limited jurisdiction issues as ordered by the Court. The deposition of relator Grynberg began in December 2002, and continued during 2003.

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, the Company is unable to provide an evaluation of the

likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company at this time.

Will Price (Price I) – On September 24, 1999, various subsidiaries of Energy Corp. were served with a class action petition filed in United States District Court, State of Kansas by Quinque Operating Company and other named plaintiffs, alleging mismeasurement of natural gas on non-federal lands. On April 10, 2003 the Court entered an order denying class certification. On May 12, 2003, Plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended petition and the court granted the motion on July 28, 2003. In this amended petition, the Company and Enogex Inc. were omitted from the case. Two subsidiaries of Enogex remain as defendants. The Plaintiffs' amended petition alleges that approximately 60 defendants, including two Enogex subsidiaries, have improperly measured natural gas. The amended petition reduces the claims to: (1) mismeasurement of volume only; (2) conspiracy, unjust enrichment and accounting; (3) a putative Plaintiffs' class of only royalty owners; and (4) gas measured in three specific states. Discovery on class certification is proceeding.

Energy Corp. intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, Energy Corp. is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to Energy Corp. at this time.

Pending Acquisition of Power Plant

On August 18, 2003, the Company signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the 520 megawatt ("MW") NRG McClain Station (the "McClain Plant"). Closing has been delayed pending receipt of FERC approval. The acquisition of this interest in the McClain Plant would clearly constitute an acquisition of electric generation ("New Generation") under the agreed settlement of the Company's rate case (the "Settlement Agreement"). The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. See Note 12 for a further description of this matter and a description of current proceedings involving a PowerSmith Cogeneration Project, L.P. ("PowerSmith") QF contract.

Environmental Laws and Regulations

Approximately $5.8 million of the Company's capital expenditures budgeted for 2004 are to comply with environmental laws and regulations.

The Company's management believes that all of its operations are in substantial compliance with present federal, state and local environmental standards. It is estimated that the Company's total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $56.0 million during 2004, compared to approximately $51.6 million utilized in 2003. 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.

In 2003, several pieces of national legislation were either introduced or reintroduced after having failed to pass in 2002. These bills could have required the reduction in emissions of sulfur dioxide ("SO2"), nitrogen oxide ("NOX"), carbon dioxide ("CO2") and mercury from the electric utility industry. Among the bills was President Bush's "Clear Skies" proposal. While not addressing CO2, this bill would require significant reductions in SO2, NOX and mercury emissions. As in 2002, none of the proposed legislation became law; however, it is expected that numerous multi-pollutant bills will again be introduced in 2004.

As required by Title IV of the Clean Air Act Amendments of 1990 ("CAAA"), the Company completed installation and certification of all required continuous emissions monitors at its generating stations in 1995. Since then, the Company has submitted emissions data quarterly to the Environmental Protection Agency ("EPA") as required by the CAAA. Beginning in 2000, the Company became subject to more stringent SO2 emission requirements. These lower limits had no significant financial impact due to the Company's earlier decision to burn low sulfur coal. In 2003, the Company's SO2 emissions were well below the allowable limits.

With respect to the NOX regulations of Title IV of the CAAA, the Company committed to meeting a 0.45 lbs/million British thermal unit ("MMBtu") NOX emission level in 1997 on all coal-fired boilers. As a result, 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 2003 were 0.32 lbs/MMBtu. However, further reductions in NOX emissions could be required if, among other things, legislation is enacted, a study currently being conducted by the state of Oklahoma determines that such NOX emissions are contributing to regional haze and that the Company's facilities impact the air quality of the Tulsa or Oklahoma City metropolitan areas, or if Oklahoma fails to meet the new fine particulate standards. Any of these scenarios would require significant capital and operating expenditures.

The Oklahoma Department of Environmental Quality's Clean Air Act Amendment Title V permitting program was approved by the EPA in March 1996. By March of 1997, the Company had submitted all required permit applications. As of December 31, 2003, 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 $0.6 million in 2003. The fees for 2004 are estimated to be approximately the same as in 2003.

Other potential air regulations have emerged that could impact the Company. On December 15, 2003, the EPA proposed regulations to limit mercury emissions from coal-fired boilers. This rule is expected to be finalized by early 2005. Earliest compliance by the Company would be January 2008. Depending upon the final regulations, this could result in significant capital and operating expenditures. In addition, on December 17, 2003, the EPA proposed an interstate air quality rule. This rule is intended to control SO2 and NOX from utility boilers in order to minimize the interstate transport of air pollution. In the proposed rule, the state of Oklahoma is exempt from any reductions. However this could change as the EPA has indicated its intentions to review Oklahoma's impact on other states. If Oklahoma is included in the final rule reductions, this could lead to significant capital and operating expenditures by the Company.

In 1997, the EPA finalized revisions to the ambient ozone and particulate standards. After a court challenge, which delayed implementation, the EPA has now begun to finalize the implementation process. Based on the most recent monitoring data, Oklahoma's Governor in July of 2003 proposed to the EPA that the entire state be designated attainment with the ozone standard. Later in 2003 the EPA approved Oklahoma's request. However, both Tulsa and Oklahoma City had previously entered into an "Early Action Compact" with the EPA whereby voluntary measures will be enacted to reduce ozone. In order to ensure that ozone levels remain below the standards, both cities intend to comply with the compact. Minimal impact on the Company's operations is expected.

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. However, Oklahoma's impact on parks in other states must also be evaluated. Sulfates and nitrate aerosols (both emitted from coal-fired boilers) can lead to the degradation of visibility. The State of Oklahoma has joined with eight other central states and has begun the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas. If an impact is determined, then significant capital expenditures could be required for both the Sooner and Muskogee generating stations.

While the United States has withdrawn its support of the Kyoto Protocol on global warming, legislation has been considered which would limit CO2 emissions. President Bush supports voluntary reductions by industry. The Company has joined other utilities in voluntary CO2 sequestration projects through reforestation of land in the southern United States. In addition, the Company has committed to reduce its CO2 emission rate (lbs. CO2/megawatt-hour) by up to five percent over the next 10 years. However, if legislation is passed requiring mandatory reductions this could have a tremendous impact on the Company's operations by requiring the Company to significantly reduce the use of coal as a fuel source.

The Company has sought and will continue to seek, new pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2003, the Company obtained refunds of approximately $0.5 million from its recycling efforts. This figure does not include the additional savings gained through the reduction and/or avoidance of disposal costs and the reduction in material purchases due to the reuse of existing materials. Similar savings are anticipated in future years.

The Company has submitted three applications during 2003 to renew its Oklahoma pollution discharge elimination system permits. The Company anticipates that the renewed permits will continue to allow operational flexibility.

The Company requested, based on the performance of a site-specific study, that the State agency responsible for the development of water quality standards adjust the in-stream copper criterion at one of its facilities. Adjustment of this criterion should allow the facility to avoid costly treatment and/or facility reconfiguration requirements. The State and the EPA have approved the new in-stream criteria for copper.

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. Final rules for existing utility sources were approved on February 16, 2004. Depending on the analysis of these final 316(b) rules, capital and/or operating costs may increase at some of the Company's generating facilities.

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

Other

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

12. Rate Matters and Regulation

Regulation and Rates

The Company's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. 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 FERC. The Secretary of the Department of Energy has jurisdiction over some of the Company's facilities and operations. For the year ended December 31, 2003, approximately 87 percent of the Company's electric revenue was subject to the jurisdiction of the OCC, nine percent to the APSC and four percent to the FERC.

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 Energy Corp. to employ accounting and other procedures and controls to protect against subsidization of non-utility activities by the Company's customers; and prohibit Energy Corp. from pledging Company assets or income for affiliate transactions.

2002 Settlement Agreement

On October 11, 2002, the Company, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to the Settlement Agreement of the

Company's rate case. The administrative law judge subsequently recommended approval of the Settlement Agreement and on November 22, 2002, the OCC signed a rate order containing the provisions of the Settlement Agreement. The Settlement Agreement provides for, among other items: (i) a $25.0 million annual reduction in the electric rates of the Company's Oklahoma customers which went into effect January 6, 2003; (ii) recovery by the Company, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) the Company to acquire New Generation of not less than 400 MWs to be integrated into the Company's generation system; and (iv) recovery by the Company, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through the Company's rider for sales to other utilities and power marketers ("off-system sales"). Previously, the Company had a 50/50 sharing mechanism in Oklahoma for any off-system sales. The Settlement Agreement provided that the first $1.8 million in annual net profits from the Company's off-system sales will go to the Company, the next $3.6 million in annual net profits from off-system sales will go to the Company's Oklahoma customers, and any net profits of off-system sales in excess of these amounts will be credited in each sales year with 80 percent to the Company's Oklahoma customers and the remaining 20 percent to the Company. If any of the $5.4 million is not recovered at the end of the three years, the OCC will authorize the recovery of any remaining costs.

Pending Acquisition of Power Plant

As part of the 2002 Settlement Agreement with the OCC, the Company undertook to acquire New Generation of not less than 400 MWs. The acquisition of a 77 percent interest in the McClain Plant would clearly constitute an acquisition of such New Generation under the Settlement Agreement. The Company expects this New Generation, including the interim purchase power agreement, will provide savings, over a three-year period, in excess of $75.0 million to its Oklahoma customers. These savings will be derived from: (i) the avoidance of purchase power contracts otherwise needed; (ii) replacing an above market cogeneration contract with PowerSmith when it can be terminated at the end of August 2004; and (iii) fuel savings associated with operating efficiencies of the new plant. These savings, while providing real savings to Oklahoma customers, are not expected to affect the profitability of the Company because the Company's rates would not need to be reduced to accomplish these savings. As indicated in the Settlement Agreement, the Company is required to provide monthly reports, for a period of 36 months after the acquisition, to the OCC Staff, documenting and providing proof of savings experienced by the Company's customers. In the event the Company is unable to demonstrate at least $75.0 million in savings to its customers during this 36-month period, the Company will have an obligation to credit its Oklahoma customers any unrealized savings below $75.0 million as determined at the end of the 36-month period, which shall be no later than December 31, 2006. PowerSmith has filed an application with the OCC seeking to compel the Company to continue purchasing power from PowerSmith's qualified cogeneration facility under PURPA at a price that would include an avoided capacity charge equal to the lesser of (i) the rate currently specified in the power purchase agreement between the Company and PowerSmith or (ii) the avoided cost of the McClain Plant. The Company does not believe that this matter should

be heard at the OCC at this time and that the avoided cost requested by PowerSmith is too high. In the event PowerSmith is ultimately successful and the Company is required to sign a purchase power agreement, it could negatively affect the Company's ability to achieve the targeted $75 million three-year customer savings under the existing terms of the Settlement Agreement. PowerSmith and the Company have been holding discussions to determine if mutually agreeable terms can be reached for a power contract between the companies providing for capacity payments to the PowerSmith facility.

In the event the Company did not acquire the New Generation by December 31, 2003, the Settlement Agreement requires the Company to credit $25.0 million annually (at a rate of 1/12 of $25.0 million per month for each month that the New Generation is not in place) to its Oklahoma customers beginning January 1, 2004 and continuing through December 31, 2006. However, if the Company purchases the New Generation subsequent to January 1, 2004, the credit to Oklahoma customers will terminate in the first month that the New Generation begins initial operations and any previously-credited amounts to Oklahoma customers will be deducted in the determination of the $75.0 million targeted savings.

On August 18, 2003, the Company signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the McClain Plant. The acquisition of this interest in the McClain Plant would clearly constitute an acquisition of New Generation under the Settlement Agreement. The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. The McClain Plant includes natural gas-fired combined cycle combustion turbine units and is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001. The owner of the remaining 23 percent in the McClain Plant is the Oklahoma Municipal Power Authority ("OMPA").

Closing is subject to customary conditions including receipt of regulatory approval by the FERC. The asset purchase agreement, as amended, provides that, unless extended, either party has the right to terminate the contract if the closing does not occur on or before March 16, 2004. Because the current owner of the McClain Plant has filed for bankruptcy protection, the acquisition also was subject to approval by the bankruptcy court. As part of the bankruptcy approval process, NRG McClain LLC's interest in the plant was subject to an auction process and on October 28, 2003, the bankruptcy court approved the sale of NRG McClain LLC's interest in the plant to the Company. Several parties have filed interventions at the FERC opposing the Company's application under Section 203 of the Federal Power Act to acquire NRG McClain's interest in the power plant or, alternatively, requesting the FERC to delay approving such acquisition. The Company believed that its application met the standards under Section 203 set forth by the FERC and that its application would be approved. On December 18, 2003, the FERC shifted its policy regarding market power issues, raised wholesale market power concerns and ordered a hearing regarding the Company's acquisition of the McClain Plant. The FERC action did not reject the Company's request to purchase the McClain Plant, but demonstrated that the Company must address certain issues. On January 20, 2004, the Company filed a petition for re-hearing of the FERC's December 18, 2003 order which included new mitigation measures that were designed to allow for prompt approval of the transaction. That request is still pending before the FERC. The Company has no indication whether the FERC will accept those proposed mitigation measures. On March 2, 2004, the Company filed

testimony and exhibits with the FERC administrative law judge. The testimony and exhibits indicate that, if the case proceeds to hearing, the wholesale market power issues that the FERC raised in the December 18, 2003 order may be resolved by the minimal mitigation measures.

Assuming the acquisition occurs, the Company expects to operate the plant in accordance with a joint ownership and operating agreement with the OMPA. Under this agreement, the Company would operate the facility, and the Company and the OMPA would be entitled to the net available output of the plant based on their respective ownership percentages. All fixed and variable costs, except fuel and gas transportation costs, would be shared in proportion to the respective ownership interests. Fuel and gas transportation costs would be shared based on consumption. The Company expects to utilize its portion of the output, 400 MWs, to serve its native load. As provided in the Settlement Agreement, pending approval of a request to increase base rates to recover the investment in the plant, the Company will have the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. Upon approval by the OCC of the Company's request, all prudently incurred costs accrued through the regulatory asset within the 12-month period will be included in the Company's prospective cost of service.

Despite the delay at the FERC, an agreement to purchase power from the McClain Plant is enabling the Company to honor the customer savings as outlined in the Settlement Agreement. On January 8, 2004, the Company filed an application with the OCC and requested that the OCC confirm the steps that the Company has taken to comply with the Settlement Agreement will result in customer savings being delivered beginning January 1, 2004, and that no further rate reduction is necessary. Various parties have intervened opposing the Company's request. If the OCC does not agree with the Company's request, the Company will be required to reduce electric rates to its Oklahoma customers by approximately $2.1 million per month and would expect to reduce expenditures for planned electric system reliability upgrades. The OCC has scheduled a hearing on April 19, 2004 for action in this case.

Assuming that the Company acquires the McClain Plant, the Company expects to fund the acquisition with a combination of a capital contribution from Energy Corp., funded in part by Energy Corp.'s equity issuance in 2003, and the issuance of long-term debt by the Company.

2003 Rate Case

On September 15, 2003, the Company filed with the OCC a notice of intent to seek an annual increase in its rates to its Oklahoma customers of more than one percent. The notice listed the following, among others, as major issues to be addressed in its application: (i) the acquisition of New Generation in accordance with the Settlement Agreement; (ii) increased capital expenditures for efficiency improvements and reliability enhancements to ensure fuel costs are minimized; and (iii) increased pension, medical and insurance costs. On October 31, 2003, the Company filed a request with the OCC to increase its rates by approximately $91 million annually. The increase was intended to pay for its pending acquisition of a 77 percent interest in the McClain Plant, allow for investment in electric system reliability and address rising business costs. The rate plan would have reduced rates for schools and more than 80,000 small businesses and non-profit organizations. On January 15, 2004, the Company

filed an application to withdraw its request for a $91 million rate increase due to the delay at FERC in receiving the necessary approvals to complete the acquisition of the McClain Plant, which was a significant part of this rate case. An order dismissing the case was issued by the OCC on January 30, 2004. On December 18, 2003, the FERC issued an order setting for hearing the Company's proposed acquisition of the McClain Plant and on January 15, 2004, the FERC administrative law judge in charge of the hearing and the parties to the case agreed to a procedural schedule that would produce a decision on the McClain Plant acquisition no sooner than the third quarter of 2004. The Company expects to file another rate case in the near future to recover increased operating and capital expenditures.

Gas Transportation and Storage Agreement

As part of the Settlement Agreement, the Company also agreed to consider competitive bidding for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. The Company believes that in order for it to achieve maximum coal generation and ensure reliable electric service, it must have firm no-notice load following service for both gas transportation and gas storage. This type of service is required to satisfy the daily swings in customer demand placed on the Company's system and still permit natural gas units to not impede coal energy production. The Company also believes that gas storage is an integral part of providing gas supply to the Company's generation facilities. Accordingly, the Company evaluated its competitive bid options in light of these circumstances. The Company's evaluation clearly demonstrates that the Enogex integrated gas system provides superior firm no-notice load following service to the Company that is not available from other companies serving the Company marketplace. On April 29, 2003, the Company filed an application with the OCC in which the Company advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of the Company's natural gas-fired generation facilities. During 2003, the Company paid Enogex approximately $44.7 million for gas transportation and storage services. Based upon requests for information from intervenors, the Company has requested from Enogex and Enogex has agreed to retain a "cost of service" consultant to assist in the preparation of testimony related to this case. On January 30, 2004, the OCC issued a procedural schedule for this case. A hearing is scheduled August 10-11, 2004 and an OCC order in the case is expected by the end of 2004. The Company believes the amount currently paid to Enogex for no-notice load following transportation and storage services is fair, just and reasonable. If any amounts paid by the Company are found not to be recoverable, the Company believes such amount would not be material.

Security Enhancements

On April 8, 2002, the Company filed a joint application with the OCC requesting approval for security investments and a rider to recover these costs from the ratepayers. On August 14, 2002, the Company filed testimony with the OCC outlining proposed expenditures and related actions for security enhancement and a proposed recovery rider. Attempting to make security investments at the proper level, the Company has developed a set of guidelines intended to minimize long-term or widespread outages, minimize the impact on critical national defense

and related customers, maximize the ability to respond to and recover from an attack, minimize the financial impact on the Company that might be caused by an attack and accomplish these efforts with minimal impact on ratepayers. The OCC Staff retained a security expert to review the report filed by the Company. The Company currently expects that hearings will be held in early 2004.

On October 17, 2003, the OCC filed a notice of inquiry to consider the issues related to the role of the OCC and Oklahoma regulated companies in addressing the security of the electrical system infrastructure and key assets. On March 4, 2004, the OCC deliberated the notice of inquiry and directed the OCC Staff to file a rulemaking proceeding for each utility industry regarding security of the electrical system infrastructure and key assets.

Other Regulatory Actions

The Settlement Agreement, when it became effective, provided for the termination of the Acquisition Premium Credit Rider ("APC Rider") and the Gas Transportation Adjustment Credit Rider ("GTAC Rider").

The APC Rider was approved by the OCC in March 2000 and was implemented by the Company to reflect 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 was to remove approximately $10.7 million annually from the amount being recovered by the Company from its Oklahoma customers in current rates.

In June 2001, the OCC approved a stipulation (the "Stipulation") to the competitive bid process of the Company's gas transportation service from Enogex. The Stipulation directed the Company to reduce its rates to its Oklahoma retail customers by approximately $2.7 million per year through the implementation of the GTAC Rider. The GTAC Rider was a credit for gas transportation cost recovery and was applicable to and became part of each Oklahoma retail rate schedule to which the Company's automatic fuel adjustment clause applies. As discussed above, the Settlement Agreement terminated the GTAC Rider. Consequently, these charges for gas transportation provided by Enogex are now included in base rates.

The Company's Generation Efficiency Performance Rider ("GEP Rider") expired in June 2002. The GEP Rider was established initially in 1997 in connection with the Company's 1996 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 percent) 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 percent) of the average fuel costs of other investor-owned utilities. In June 2000 the OCC made modifications to the GEP Rider which 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 January 1, 2002 and June 30, 2002, the Company recovered approximately $2.4 million under the GEP Rider.

State Restructuring Initiatives

Oklahoma

As previously reported, the Electric Restructuring Act of 1997 (the "1997 Act") was initially designed to provide retail customers in Oklahoma a choice 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 1997 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 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, this legislation called for a nine-member task force to further study the issues surrounding deregulation. The task force includes the Governor or his designee, the Oklahoma Attorney General, the OCC Chair and several legislative leaders, among others. In the 2003 legislative session, additional legislation was introduced to repeal the 1997 Act, but the 2003 legislative session ended without any further action to repeal the 1997 Act. It is unknown at this time whether the 1997 Act will be repealed. The Company will continue to actively participate in the legislative process and expects to remain a competitive supplier of electricity. As a result of the failures of California's attempt to deregulate its electricity markets, the Enron bankruptcy, and associated impacts on the industry, efforts to restructure the electricity market in Oklahoma appear at this time to be delayed indefinitely.

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 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. In March 2003, the Restructuring Law was repealed. As part of the repeal legislation, electric public utilities are permitted to recover transition costs. The Company incurred approximately $2.4 million in transition costs necessary to carry out its responsibilities associated with efforts to implement retail open access. On January 20, 2004, the APSC issued an order which authorized the Company to recover approximately $1.9 million in transition costs over an 18-month period beginning February 2004.

13. Fair Value of Financial Instruments

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

	2003		2002	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				

Interest Rate Swaps	**$**	**4.0**	**$**	**4.0**	$	7.5	$	7.5
Long-Term Debt								
Senior Notes	**$**	**571.8**	**$**	**611.8**	$	575.1	$	617.2
Industrial Authority Bonds		**135.4**		**135.4**		135.4		135.4

The carrying value of the financial instruments on the accompanying Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company's interest rate swap was determined primarily based on quoted market prices. The fair value of the Company's long-term debt is based on quoted market prices.

14. Subsequent Event (Unaudited)

Sooner Power Plant Coal Dust Explosion

On February 16, 2004, there was a coal dust explosion at the Company's Sooner Power Plant which caused structural and electrical damage to the coal train unloading system. The generation capacity of the Sooner Plant facility has not been impacted by this incident. The estimated damage costs are between approximately $3.0 million and $4.0 million. The Company expects that the coal train unloading system will be ready to unload coal trains by April 2, 2004. In the meantime, Sooner Power Plant continues to generate power by using coal from the storage pile. Energy Corp. is self-insured for this loss.

REPORT OF INDEPENDENT AUDITORS

The Board of Directors and Stockholder
Oklahoma Gas and Electric Company

We have audited the accompanying balance sheets and statements of capitalization of Oklahoma Gas and Electric Company as of December 31, 2003 and 2002, and the related statements of income, retained earnings, comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with 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 at December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth herein.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
January 30, 2004

REPORT OF MANAGEMENT

To Our Stockholder:

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 auditors 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, 2003, 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 auditors to review matters relating to financial reporting, auditing and internal control. To ensure auditor independence, both the internal auditors and independent auditors have full and free access to the Audit Committee.

The independent public accounting firm of Ernst & Young 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/ Donald R. Rowlett	/s/ James R. Hatfield
Donald R. Rowlett, Vice President and Controller	James R. Hatfield, Senior Vice President and Chief Financial Officer

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 *(In millions)*		Dec 31	Sep 30	Jun 30	Mar 31
Operating revenues	**2003**	**$ 286.3**	**$ 540.3**	**$ 357.9**	**$ 332.6**
	2002	284.8	488.9	352.2	262.1
Operating income (loss)	**2003**	**$ (2.0)**	**$ 160.8**	**$ 55.3**	**$ 2.1**
	2002	6.2	170.2	56.9	5.8
Net income (loss)	**2003**	**$ (4.3)**	**$ 95.1**	**$ 27.9**	**$ (3.3)**
	2002	(1.6)	98.4	30.8	(1.5)

Security Ratings*

	Moody's	Standard & Poor's	Fitch's
Company Senior Notes	A2	BBB+	AA-

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

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

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

None

Item 9A. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), of the effectiveness of the Company's disclosure controls and procedures, the CEO and CFO have concluded that the Company's disclosure controls and procedures are effective.

Subsequent to the date of their evaluation, there have been no significant changes in the Company's internal controls or in other factors that could significantly affect these controls.

No change in the Company's internal control over financial reporting has occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

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 and Related Stockholder Matters.

Item 13. Certain Relationships and Related Transactions.

Item 14. Principal Accountant Fees and Services.

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, 13 and 14 has been omitted.

PART IV

Item 15. 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, 2003 and 2002
- Statements of Capitalization at December 31, 2003 and 2002
- Statements of Income for the years ended December 31, 2003, 2002 and 2001
- Statements of Retained Earnings for the years ended December 31, 2003, 2002 and 2001
- Statements of Comprehensive Income for the years ended December 31, 2003, 2002 and 2001
- Statements of Cash Flows for the years ended December 31, 2003, 2002 and 2001
- Notes to Financial Statements
- Report of Independent Auditors
- Report of Management

Supplementary Data

- Interim Financial Information

2. Financial Statement Schedule (included in Part IV)	Page

Schedule II - Valuation and Qualifying Accounts 124

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.

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3. Exhibits

Exhibit No.	**Description**
2.01	Asset Purchase Agreement, dated as of August 18, 2003 by and between the Company and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to Energy Corp.'s Form 8-K dated August 18, 2003 (File No. 1-12579) and incorporated by reference herein)
2.02	Amendment No. 1 to Asset Purchase Agreement, dated as of October 22, 2003 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.03 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.03	Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.04 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.04	Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.05 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.05	Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.06 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.06	Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.07 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
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 the Company to Boatmen's First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to Registration Statement No. 33-61821 and incorporated by reference herein)

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4.02	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 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 the Company's Form 8-K filed on July 17, 1997 (File No. 1-1097) and incorporated by reference herein)
4.04	Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to the Company's Form 8-K filed on April 16, 1998 (File No. 1-1097) and incorporated by reference herein)
4.05	Supplemental Indenture No. 4, dated as of October 15, 2000, being a supplement instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to the Company'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 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 for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

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

10.07 Energy Corp.'s 2003 Stock Incentive Plan. (Filed as Annex A to Energy Corp.'s Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)

10.08 Oklahoma Gas and Electric Company Restoration of Retirement Income Plan, as amended by Amendments No. 1 and No. 2. (Filed as Exhibit 10.12 to Energy Corp.'s Form 10-K for the year ended December 31, 1996 (File No.1-12579) and incorporated by reference herein)

10.09 Amendment No. 3 to the Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to Energy Corp.'s Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

10.10 Amendment No. 4 to the Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.14 to Energy Corp.'s Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

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

10.12 Energy Corp.'s 2003 Annual Incentive Compensation Plan. (Filed as Annex B to Energy Corp.'s Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)

10.13 Energy Corp.'s Deferred Compensation Plan and Amendment No. 1 to Energy Corp.'s Deferred Compensation Plan. (Filed as Exhibit 10.12 to Energy Corp.'s Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.14 Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to the Company's rate case. (Filed as Exhibit 99.02 to Energy Corp.'s Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12579) and incorporated by reference herein)

10.15 Credit Agreement dated June 26, 2003 between the Company, Bank One, NA, Wachovia Bank, National Association, Cobank, ACB and LaSalle Bank National Association. (Filed as Exhibit 10.01 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12579) and incorporated by reference herein)

10.16 Amended and Restated Facility Operating Agreement dated December 17, 2003 between the Company and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.23 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)

10.17 Amended and Restated Ownership and Operation Agreement dated December 17, 2003 between the Company and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.24 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)

12.01 Calculation of Ratio of Earnings to Fixed Charges.

16.01 Letter of Arthur Andersen LLP regarding change in certifying accountant. (Filed as Exhibit 16.01 to the Company's Form 8-K filed on May 21, 2002 (File No. 1-1097) and incorporated by reference herein)

23.01 Consent of Ernst & Young LLP.

24.01 Power of Attorney.

31.01 Certifications Pursuant to Rule 13a-15(e)/15d-15(e) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.01 Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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

Executive Compensation Plans and Arrangements

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 for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

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(b) Reports on Form 8-K

The Company filed a Current Report on Form 8-K on October 31, 2003 to report that it filed a request with the OCC to increase its rates by approximately $91 million annually.

The Company filed a Current Report on Form 8-K on November 12, 2003 to report its results of operations and financial condition for the third quarter of 2003.

The Company filed a Current Report on Form 8-K on December 2, 2003 to report that the Company and NRG McClain LLC agreed to amend the asset purchase agreement to extend the optional termination date of the asset purchase agreement.

The Company filed a Current Report on Form 8-K on December 18, 2003 to report that the FERC ordered a hearing regarding the acquisition of the NRG McClain power plant by the Company.

The Company filed a Current Report on Form 8-K on January 16, 2004 to report that the Company withdrew its request for a $91 million rate increase.

The Company filed a Current Report on Form 8-K on January 28, 2004 to report its results of operations and financial condition for the fourth quarter and year ended December 31, 2003.

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
			(In millions)		
Year Ended December 31, 2001					
Reserve for Uncollectible Accounts	$ 3.7	$ 15.8	$ ---	$ 13.3 (A)	$ 6.2
Year Ended December 31, 2002					
Reserve for Uncollectible Accounts	$ 6.2	$ 6.5	$ ---	$ 8.0 (A)	$ 4.7
Year Ended December 31, 2003					
Reserve for Uncollectible Accounts	$ 4.7	$ 2.3	$ ---	$ 4.4 (A)	$ 2.6

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, and State of Oklahoma on the 8th day of March, 2004.

OKLAHOMA GAS AND ELECTRIC COMPANY
(Registrant)

By /s/ Steven E. Moore

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 8, 2004
/ s / James R. Hatfield James R. Hatfield	Principal Financial Officer; and	March 8, 2004
/ s / Donald R. Rowlett Donald R. Rowlett	Principal Accounting Officer.	March 8, 2004
Herbert H. Champlin	Director;	
Luke R. Corbett	Director;	
William E. Durrett	Director;	
Martha W. Griffin	Director;	
John D. Groendyke	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 8, 2004

Supplemental Information to Be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act.

The Registrant has not sent, and does not expect to send, an annual report or proxy statement to its security holders.

Exhibit Index

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12.01 Calculation of Ratio of Earnings to Fixed Charges.

16.01 Letter of Arthur Andersen LLP regarding change in certifying accountant. (Filed as Exhibit 16.01 to the Company's Form 8-K filed on May 21, 2002 (File No. 1-1097) and incorporated by reference herein)

23.01 Consent of Ernst & Young LLP.

24.01 Power of Attorney.

31.01 Certifications Pursuant to Rule 13a-15(e)/15d-15(e) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.01 Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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

Exhibit 12.01

Oklahoma Gas and Electric Company
S E C Method of
Ratio of Earnings to Fixed Charges

	Year Ended	Year Ended	Year Ended	Year Ended	Year Ended

	Dec 31, 1999	Dec 31, 2000	Dec 31, 2001	Dec 31, 2002	Dec 31, 2003
Earnings:					
Net Income	$ 139,041,196	$ 142,391,955	$ 121,206,243	$ 126,063,042	$ 115,427,897
Add Income Taxes	84,964,966	80,342,171	69,425,700	71,509,149	60,176,789
Add Fixed Charges	50,124,012	52,948,444	49,953,948	44,577,061	42,582,265
Subtotal	274,130,174	275,682,570	240,585,891	242,149,252	218,186,951
Subtract:					
Allowance for funds used during construction	719,576	2,229,277	707,822	905,189	538,624
Total Earnings	273,410,598	273,453,293	239,878,069	241,244,063	217,648,327
Fixed Charges:					
Long-term debt interest expense	44,813,022	45,857,811	42,256,284	38,171,798	36,899,911
Other interest expense	1,845,150	3,151,243	4,438,997	3,044,837	2,443,702
Calculated interest on leased property	3,465,840	3,939,390	3,258,667	3,360,426	3,238,652
Total Fixed Charges	$ 50,124,012	$ 52,948,444	$ 49,953,948	$ 44,577,061	$ 42,582,265
Ratio of Earnings to Fixed Charges	5.45	5.16	4.80	5.41	5.11

Exhibit 23.01

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement (Form S-3 No. 333-104615) pertaining to debt securities, of our report dated January 30, 2004, with respect to the financial statements and schedule of Oklahoma Gas and Electric Company in the Annual Report (Form 10-K) for the year ended December 31, 2003.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
March 3, 2004

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, 2003; 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 21st day of January, 2004.

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
John D. Groendyke, Director	/ s / John D. Groendyke
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 21st day of January, 2004.

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

My Commission Expires:
May 3, 2007

Exhibit 31.01

CERTIFICATIONS

I, Steven E. Moore, certify that:

1. I have reviewed this annual report on Form 10-K of Oklahoma Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 8, 2004
/s/ Steven E. Moore

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

Exhibit 31.01

CERTIFICATIONS

I, James R. Hatfield, certify that:

1. I have reviewed this annual report on Form 10-K of Oklahoma Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 8, 2004
/s/ James R. Hatfield

James R. Hatfield
Senior Vice President and
Chief Financial Officer

Exhibit 32.01

Certification Pursuant to 18 U.S.C. Section 1350
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Oklahoma Gas and Electric Company (the "Company") on Form 10-K for the period ended December 31, 2003, as filed with the Securities and Exchange Commission (the "Report"), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 8, 2004

/s/ Steven E. Moore

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

/s/ James R. Hatfield

James R. Hatfield
Senior Vice President and
Chief Financial Officer

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; 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 natural gas on both a global and regional basis, including commodity price changes, market supply shortages, interest rate changes and counter party default;

- Economic conditions including availability of credit, actions of rating agencies and their impact on our ability to access the capital markets, inflation rates and monetary fluctuations;

- Customer business conditions including demand for their products or services and supply of labor and materials used in creating their products and services;

- Financial or regulatory accounting principles or policies imposed by the Financial Accounting Standards Board, the Securities and Exchange Commission, the Federal Energy Regulatory Commission, state public utility commissions, state entities which regulate natural gas transmission, gathering and processing and similar entities with regulatory oversight;

- Availability or cost of capital such as changes in: interest rates, market perceptions of the utility and energy-related industries, the Company or any of its subsidiaries or security ratings;

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, unusual maintenance or repairs; unanticipated changes to fossil fuel or gas supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints;

- Employee workforce factors including changes in key executives;
- 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 and divestitures;
- 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 11 of Notes to Consolidated Financial Statements of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, 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.