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

FORM 10-Q

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2002

OR

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

Commission File Number: 1-12579

OGE Energy Corp.

(Exact name of registrant as specified in its charter)

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

321 North Harvey
P.O. Box 321
Oklahoma City, Oklahoma 73101-0321
(Address of principal executive offices)
(Zip Code)

405-553-3000
(Registrant's telephone number, including area code)

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 ___

As of April 30, 2002, 77,999,512 shares of common stock, par value $0.01 per share were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED MARCH 31, 2002

TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2002	December 31, 2001
	(In thousands)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 748	$ 32,493
Accounts receivable - customers, less reserve of $7,446 and $8,863, respectively	224,056	205,155
Accrued unbilled revenues	30,800	35,600
Accounts receivable - other	24,700	16,958
Fuel inventories, at LIFO cost	69,635	77,209
Materials and supplies, at average cost	50,060	38,736
Prepayments and other	36,922	41,103
Price risk management	19,085	21,238
Accumulated deferred tax assets	9,879	10,035
Total current assets	465,885	478,527
OTHER PROPERTY AND INVESTMENTS, at cost	41,341	40,318
PROPERTY, PLANT AND EQUIPMENT		
In service	5,526,174	5,507,240
Construction work in progress	101,130	47,812
Total property, plant and equipment	5,627,304	5,555,052
Less accumulated depreciation	2,324,000	2,291,304
Net property, plant and equipment	3,303,304	3,263,748
DEFERRED CHARGES		
Advance payments for gas	8,500	8,500
Income taxes recoverable through future rates	37,356	37,615
Intangible asset - unamortized prior service cost	47,318	47,318
Prepaid benefit obligation	14,102	21,315
Price risk management	1,790	13,390
Other	89,998	85,861
Total deferred charges	199,064	213,999
TOTAL ASSETS	$ 4,009,594	$ 3,996,592

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)
(Unaudited)

	March 31, 2002	December 31, 2001
	(In thousands)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 97,000	$ 115,000
Accounts payable	205,603	153,223

Dividends payable	25,932	25,909
Customers' deposits	29,656	28,423
Accrued taxes	8,668	28,835
Accrued interest	30,352	40,314
Long-term debt due within one year	115,000	115,000
Provision for payments of take or pay gas	30,800	30,800
Fuel clause over recoveries	28,795	23,358
Price risk management	7,797	7,925
Other	33,547	30,951
Total current liabilities	613,150	599,738
LONG-TERM DEBT	1,521,950	1,526,303
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligation	100,947	100,086
Accumulated deferred income taxes	664,136	634,946
Accumulated deferred investment tax credits	50,991	52,279
Price risk management	8,961	3,759
Other	40,877	38,912
Total deferred credits and other liabilities	865,912	829,982
STOCKHOLDERS' EQUITY		
Common stockholders' equity	444,781	444,689
Retained earnings	585,746	617,924
Accumulated other comprehensive income (loss), net of tax	(21,945)	(22,044)
Total stockholders' equity	1,008,582	1,040,569
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 4,009,594	$ 3,996,592

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31	
	2002	**2001**
	(In thousands, except per share data)	
OPERATING REVENUES	$ 595,090	$ 1,063,587
COST OF GOODS SOLD	427,430	896,923
Gross margin on revenues	167,660	166,664
Other operation and maintenance	88,538	98,090
Depreciation and amortization	46,983	45,324
Taxes other than income	16,872	16,650
OPERATING INCOME	15,267	6,600
OTHER INCOME (EXPENSES), NET	1,041	(250)
EARNINGS BEFORE INTEREST AND TAXES	16,308	6,350
INTEREST INCOME (EXPENSES)		
Interest income	511	869
Interest on long-term debt	(22,029)	(26,441)
Interest on trust preferred securities	(4,317)	(4,317)
Allowance for borrowed funds used during construction	378	183
Other interest charges	(2,575)	(3,706)

Net interest income (expenses)	(28,032)	(33,412)
LOSS BEFORE TAXES	(11,724)	(27,062)
INCOME TAX BENEFIT	(5,501)	(12,093)
NET LOSS	$ (6,223)	$ (14,969)
BASIC AND DILUTED AVERAGE COMMON SHARES OUTSTANDING	77,992	77,922
BASIC AND DILUTED LOSS PER AVERAGE COMMON SHARE	$ (0.08)	$ (0.19)
DIVIDENDS PAID PER SHARE	$ 0.3325	$ 0.3325

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31	
	2002	**2001**
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Loss	$ (6,223)	$ (14,969)
Adjustments to reconcile net loss to net cash provided from operating activities		
Depreciation and amortization	46,983	45,324
Deferred income taxes and investment tax credits, net	3,462	3,947
Gain on sale of assets	(2,074)	(53)
Change in certain assets and liabilities		
Accounts receivable - customers	(18,901)	129,783
Accrued unbilled revenues	4,800	6,700
Fuel, materials and supplies inventories	(3,750)	109,461
Accumulated deferred tax assets	156	---
Other current assets	(3,561)	19,916
Accounts payable	52,380	(44,075)
Accrued taxes	(20,167)	(29,350)
Accrued interest	(9,962)	(10,815)
Price risk management	13,851	6,372
Other current liabilities	9,289	(203)
Other operating activities	23,611	(10,947)
Net Cash Provided from Operating Activities	89,894	211,091
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(87,695)	(59,540)
Proceeds from sale of assets	10,262	72
Other investing activities	(344)	(425)
Net Cash Used in Investing Activities	(77,777)	(59,893)
CASH FLOWS FROM FINANCING ACTIVITIES		
Retirement of long-term debt	---	(4,883)
Retirement of short-term debt, net	(18,000)	(120,200)
Premium on issuance (retirement) of common stock	93	(125)
Obligation under capital lease	---	(184)
Cash dividends declared on common stock	(25,955)	(25,928)
Net Cash Used in Financing Activities	(43,862)	(151,320)
NET DECREASE IN CASH AND CASH EQUIVALENTS	(31,745)	(122)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	32,493	454
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 748	$ 332
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
CASH PAID DURING THE PERIOD FOR		
Interest (net of amount capitalized $378 and $183)	$ 45,532	$ 41,578
Income taxes	$ ---	$ 1,800

NON-CASH INVESTING AND FINANCING ACTIVITIES				
Interest rate swap..	$	3,464	$	---
Change in fair value of long-term debt..........................	$	(4,341)	$	---

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

OGE ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Significant Accounting Policies

Organization

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

OG&E generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. OG&E's operations are subject to the jurisdiction of the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). OG&E owns and operates eight generating stations and is the largest electric utility in Oklahoma. OG&E's franchised service territory includes the Fort Smith, Arkansas area, which is the second largest market in that state.

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

Basis of Consolidation

The condensed consolidated financial statements included herein have been prepared by the Company, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been condensed or omitted pursuant to such rules and regulations; however, the Company believes that the disclosures are adequate to prevent the information presented from being misleading.

In the opinion of management, all adjustments necessary to present fairly the consolidated financial position of the Company at March 31, 2002 and December 31, 2001, and the results of operations and cash flows for the three months ended March 31, 2002 and 2001, have been included and are of a normal recurring nature. Certain amounts have been reclassified on the condensed consolidated financial statements to conform to the 2002 presentation.

Operating results for the three months ended March 31, 2002 are not necessarily indicative of the results that may be expected for the year ending December 31, 2002 or for any future period. In preparing these condensed consolidated financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the condensed consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The accompanying condensed consolidated financial statements and notes thereto should be read in conjunction with the audited consolidated financial statements and notes thereto included in the Company's Form 10-K for the year ended December 31, 2001.

Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to the accounting principles prescribed by the Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 provides that certain costs that would otherwise be charged to expense can be deferred as regulatory assets, based on expected recovery from customers in future rates. Likewise, certain credits that would otherwise reduce expense are deferred as regulatory liabilities based on expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment. At March 31, 2002, regulatory assets and regulatory liabilities are being amortized and reflected in rates charged to customers over periods up to 20 years.

Cash and Cash Equivalents

For purposes of these condensed consolidated financial statements, the Company considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates market.

2. Accounting Pronouncements

Effective January 1, 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB 133" and SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities." SFAS No. 133 requires the Company to record all derivatives on the Balance Sheet

at fair value. Changes in the fair value of derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, must be recognized as a derivative fair value gain or loss in the accompanying Consolidated Statements of Operations. Changes in the fair value of effective fair value hedges are recorded in Price Risk Management in the accompanying Consolidated Balance Sheets, with a corresponding net change in the hedged asset or liability. Changes in the fair value of effective cash flow hedges are recorded as a component of Accumulated Other Comprehensive Income, which is later reclassified to earnings when the hedged transaction occurs. Physical delivery contracts, which are deemed to be normal purchases or normal sales, are not accounted for as derivatives.

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

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

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

3. Price Risk Management Activities

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

4. Comprehensive Income

The components of total comprehensive income for the three months ended March 31, 2002 and 2001, respectively, are as follows:

	Three Months Ended March 31	
	2002	2001
	(In thousands)	
Net loss	$ **(6,223)**	$ (14,969)
Other comprehensive income (loss), net of tax:		
Transition adjustment	**---**	(16,492)
Change in derivative fair value	**---**	15,733
Reclassification adjustments - contract settlements	**(99)**	(1,303)
Total other comprehensive loss, net of tax	**(99)**	(2,062)
Total comprehensive loss	$ **(6,322)**	$ (17,031)

The components of accumulated other comprehensive income as of March 31, 2002 are as follows:

	March 31, 2002
	(In thousands)
Balance at December 31, 2001	$ (22,044)
Reclassification adjustments - contract settlements	99
	$ (21,945)

5. Asset Disposals

In March 2002, Enogex sold all of its interests in Belvan Corporation, Belvan Limited Partnership and Todd Ranch Limited Partnership to West Texas Gas, Inc. Belvan Limited Partnership and Todd Ranch Limited Partnership had approximately 344 miles of gathering lines in Crockett and Pecos counties in Texas. Enogex had acquired these entities in 1998.

After a review of Enogex's assets on the basis of their strategic and financial value, the Company has decided to seek to sell its exploration and production assets by year end 2002. The book value of these assets was approximately $43 million as of March 31, 2002.

6. Long-Term Debt

During 2001, the Company entered into two separate interest rate swap agreements: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110 million of 7.30 percent fixed rate debt, due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate ("LIBOR") and (ii) Enogex entered into an interest rate swap agreement, effective July 15, 2001, to convert $200 million of 8.125 percent fixed rate debt due, January 15, 2010, to a variable rate based on LIBOR. On March 1, 2002, Enogex monetized its interest rate swap agreement and received cash of $4.2 million, which will be amortized over the life of the related debt.

On March 4, 2002, Enogex entered into a new interest rate swap agreement to convert $200 million of 8.125 percent fixed rate debt due, January 15, 2010, to a variable rate based on LIBOR.

These interest rate swaps qualified as fair value hedges under SFAS No. 133 and meet all requirements for a determination that there was no ineffective portion as allowed under the shortcut method under SFAS No. 133.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction

OGE Energy Corp. (collectively with its subsidiaries, the "Company") is an energy and energy services provider offering physical delivery and management of both electricity and natural gas in the south central United States. The Company conducts these activities through two business segments, the electric utility and the energy supply segments.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through Oklahoma Gas and Electric Company ("OG&E") and are subject to the jurisdiction of the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory

Commission ("FERC"). OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area, which is the second largest market and an area of high growth in that state. OG&E is expected to grow moderately, consistent with historic trends. Expansion will primarily result from continued economic growth in its service territory.

The energy supply segment produces, gathers, processes, transports, markets and stores natural gas; produces, transports and markets natural gas liquids; provides commodity sales and services related to natural gas and electric power; and provides energy-related services for corporate commodity price risk management and energy forward price evaluations. These operations are conducted through Enogex Inc. and its subsidiaries ("Enogex"). Within the energy supply segment, Enogex's activities are further subdivided into four categories: transportation and storage; gathering and processing; marketing and trading; and exploration and production.

Enogex owns and operates the tenth largest natural gas pipeline system in the United States in terms of miles of pipe in service. Enogex has a significant investment in natural gas gathering, processing, transmission and storage in the major gas producing basins of Oklahoma. Enogex also has investments in exploration and production of natural gas and oil with properties located primarily in Michigan and Oklahoma.

Forward-Looking Statements

Except for the historical statements contained herein, some matters discussed in this Form 10-Q, including the discussion in "2002 Outlook", are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate", "estimate", "objective", "possible", "potential" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including their impact on capital expenditures; prices of electricity, natural gas and natural gas liquids, each on a stand-alone basis and in relation to each other; business conditions in the energy industry; competitive factors including the extent and timing of the entry of

additional competition in the markets served by the Company; unusual weather; state and federal legislative and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the Company's markets, including rate recovery for January 2002 storm damages; and other risk factors listed in the Company's Form 10-K for the year ended December 31, 2001, including Exhibit 99.01 thereto and other factors described from time to time in the Company's reports filed with the Securities and Exchange Commission.

Overview

The following discussion and analysis presents factors which affected the Company's consolidated results of operations for the three months ended March 31, 2002 (the "current period") as compared to the three months ended March 31, 2001 (the "prior period"), and the Company's consolidated financial position as of March 31, 2002. Due to seasonal fluctuations and other factors, the operating results for the current period are not necessarily indicative of the results that may be expected for the year ending December 31, 2002 or for any future period. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

The Company reported a loss of $0.08 per share in the current period, compared with a loss of $0.19 per share for the prior period. The improvement in financial performance was primarily due to increased profit margins at Enogex and lower interest expenses.

OG&E posted a loss of $0.02 per share in the current period, compared with a loss of $0.01 per share for the prior period. This slight decrease in earnings at OG&E was attributable to a variety of factors, including timing differences in fuel cost recoveries from Arkansas customers.

Enogex posted a loss of $0.02 per share in the current period, compared with a loss of $0.12 per share for the prior period. Enogex's improvement in the current period was primarily attributable to increased profit margins in transportation and storage, gathering and processing, and marketing and trading.

The results on a stand-alone basis of the Company (i.e., as a holding company), which has expenses but no revenues, reflect a loss of $0.04 per share in the current period, compared with a loss of $0.06 per share for the prior period. These results are primarily attributable to lower interest expenses.

Actions of the regulatory commissions that set OG&E's electric rates will continue to affect the Company's financial results. In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of OG&E. OG&E's rates had last been formally reviewed in 1995. In the filing, the OCC requested that OG&E submit information in accordance with OCC minimum standard filing requirements by January 28, 2002 for a test year ending September 30, 2001. On January 28, 2002, OG&E filed its response requesting a $22 million annual rate increase. It has been 16 years since OG&E requested a rate increase. Approximately $10 million of the requested rate increase relates to enhanced security

as a result of the September 11, 2001 terrorist attacks and approximately $12 million relates to increased capacity needs and system reliability.

On January 30, 2002, a significant ice storm hit OG&E's service territory and inflicted major damage to the transmission and distribution infrastructure with total expenditures estimated at $136 million. Of the $136 million, approximately $115 million was related to capital expenditures and $21 million for operation and maintenance. The ice storm affected approximately 195,000 of OG&E's customers and approximately 15,000 square miles of OG&E's service territory. On April 8, 2002, OG&E announced it would request the approval of the OCC to withdraw the $10 million increased security portion of OG&E's January 2002 rate filing. Instead, OG&E intends to work with the OCC Staff under a joint filing to determine the appropriate dollar amount for security upgrades. In place of the security portion of the January 2002 rate filing, OG&E is requesting the OCC to include in the rate case relief from the estimated $136 million in damages caused by the ice storm. The area of damage is within counties that were declared a federal disaster area. Therefore, OG&E is also seeking recovery of a portion of the storm damages from the Federal government with the assistance of the OCC and the Oklahoma Congressional delegation. The operating and capital expenditures for restoration of the transmission and distribution infrastructure have been either capitalized as part of the Company's property, plant and equipment or deferred pending recovery through regulation or other alternatives. Accordingly, these expenditures did not impact the current period operating results. If the OCC does not approve recovery of these costs, then future periods could be negatively impacted by the immediate recognition of the deferred operating expenses. On May 8, 2002, the OCC ordered a two month delay in the procedural schedule of OG&E's rate case. The delay will allow more time for reporting and auditing the expenditures associated with the ice storm. A final order in OG&E's rate case is not expected until later in 2002. At this time, management cannot predict the outcome of this rate case or the impact on its consolidated financial position or results of operations. See "Regulation and Rates-Recent Regulatory Matters" for further discussion of these developments.

OG&E has been and will continue to be affected by competitive changes to the utility industry. Significant changes already have occurred in the wholesale electric markets at the federal level and significant changes are expected at the retail level in the states served by the Company. In Oklahoma, deregulation of the electric industry has been postponed until at least 2003. See "Regulation and Rates-State Restructuring Initiatives" for further discussion of these developments.

In March 2002, Enogex sold all of its interests in Belvan Corporation, Belvan Limited Partnership and Todd Ranch Limited Partnership to West Texas Gas, Inc. Belvan Limited Partnership and Todd Ranch Limited Partnership had approximately 344 miles of gathering lines in Crockett and Pecos counties in Texas. Enogex had acquired these entities in 1998.

2002 Outlook

The Company expects that earnings in 2002 will be between $1.60 and $1.80 per share, assuming normal weather in the electric utility service area. The Company anticipates a

minimum contribution of approximately $1.60 per share from OG&E, a minimum contribution of $0.19 per share from Enogex and an $0.18 per share loss from results on a stand-alone basis as a holding company. The Company also expects to maintain its annual dividend of $1.33 per share. The Company's earnings estimate for 2002 does not include any of the expenditures associated with the January 2002 ice storm, which, as discussed previously, are currently being capitalized or deferred.

The foregoing estimate of earnings per share assumes OG&E's revenues will increase primarily due to growth in the number of customers and usage by existing customers and a return to more normal weather. These increases in revenues will be partially offset by the expiration of the Generation Efficiency Performance Rider ("GEP Rider") in mid-2002 as discussed below.

During 2002 and without regard to the ice storm discussed previously, the Company expects OG&E's operating and maintenance expense to remain relatively flat as compared to 2001. The Company does expect an increase in property and casualty insurance premiums largely as a result of the September 11, 2001 terrorist attacks, however, this increase should be offset by other operating costs.

During 2002, the Company expects approximately 64 percent of Enogex's earnings before interest and taxes ("EBIT") to be generated by transportation and storage due to increased revenues attributable to, among other things, two new long-term transportation contracts with independent power producers ("IPPs"). One of these IPPs is refusing to make (i) a prepayment in the amount of $1.6 million which, in Enogex's opinion, became effective due to the IPP falling below contractual creditworthiness provisions; and (ii) payments of the monthly demand fees, totaling approximately $1.1 million, due to Enogex, on grounds of an alleged force majeure event. Additionally, the parent corporation of the IPP has refused to pay Enogex under a guarantee for the transportation fees and prepayment obligations. The Company believes that the contractual obligations discussed above and the prepayment are owed and will take appropriate action to protect its legal position. The Company expects approximately 27 percent of Enogex's EBIT to be generated by gathering and processing due to increased revenues, increased fractionation spreads and a better processing environment. The Company's earnings estimate for 2002 assumes a fractionation spread (i.e., the value of liquids after they are processed out of natural gas, less the gas itself) of $1.00 per MMBtu. A $0.10 per MMBtu change in the fractionation spread generally increases or decreases gross margin on revenues ("gross margin") by approximately $2.3 million. Margins in gathering and processing should also be favorably impacted by the effects of a treating fee that Enogex began utilizing in the current period. Under the treating fee, shippers are charged a fee for gas that requires processing for delivery into interstate pipelines when the fractionation spreads are not sufficient to cover the cost of processing the gas, as was experienced in 2001. The Company expects approximately eight percent of Enogex's EBIT to be generated by marketing and trading through improved gas marketing efforts. The remaining one percent of Enogex's EBIT initially was expected to come from exploration and production. After a review of Enogex's assets on the basis of their strategic and financial value, the Company has decided to seek to sell its exploration and production assets by year end 2002. The book value of these assets was approximately $43 million as of March 31, 2002.

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

Results of Operations

(In thousands, except per share data)	Three Months Ended March 31 **2002**	2001
Operating income	**$ 15,267**	$ 6,600
Earnings before interest and taxes	**$ 16,308**	$ 6,350
Average common shares outstanding	**77,992**	77,922
Loss per average common share	**$ (0.08)**	$ (0.19)
Dividends paid per share	**$ 0.3325**	$ 0.3325

In reviewing its operating results, the Company believes that it is appropriate to focus on operating income and EBIT as reported on its Consolidated Statements of Operations. Operating income for the current period was $15.3 million compared to $6.6 million for the prior period. EBIT was $16.3 million for the current period compared to $6.4 million for the prior period. The only difference between operating income and EBIT is the inclusion of certain minor non-operating activities in EBIT. EBIT is summarized in the following table and is discussed by business segment thereafter.

EBIT by Business Segment

(In thousands)	Three Months Ended March 31 **2002**	2001
OG&E (Electric Utility)	**$ 5,424**	$ 8,411
Enogex (Energy Supply)	**10,404**	(1,674)
Other operations (1)	**480**	(387)
Consolidated EBIT	**$ 16,308**	$ 6,350

(1) Other operations primarily include unallocated corporate expenses and interest expense on commercial paper.

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

OG&E

(In thousands)	Three Months Ended March 31 **2002**	2001
Operating revenues	**$ 262,083**	$ 326,835
Fuel	**84,992**	126,962
Purchased power	**63,843**	76,969
Gross margin on revenues	**113,248**	122,904
Other operating expenses	**107,416**	113,702
Operating income	**5,832**	9,202
Other expenses, net	**(408)**	(791)
EBIT	**$ 5,424**	$ 8,411
System sales - MWH (a)	**5,579**	5,604
Off-system sales - MWH	**136**	67
Total sales - MWH	**5,715**	5,671

(a) Megawatt-hour

OG&E's EBIT for the current period decreased approximately $3.0 million or 35.5 percent compared to the prior period. The decrease in EBIT was primarily the result of timing differences in the recovery of lower fuel cost expenses from Arkansas customers and the loss of revenue resulting from the January 2002 ice storm, offset by reduced bad debt expense.

The gross margin decreased approximately $9.7 million in the current period compared to the prior period. The gross margin was reduced by approximately $4.8 million due to lower recoveries of fuel costs from Arkansas customers through that state's automatic fuel adjustment clause. 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. Although total expenditures from the January 2002 ice storm, which have been capitalized or deferred, did not impact the current period operating results, the related loss of revenue due to interrupted power to our customers in addition to decreased consumption by existing customers and a 4.7 percent lower amount of heating degree days in the current period decreased gross margin by approximately $3.8 million. Lower recoveries under the GEP Rider decreased the gross margin by approximately $0.4 million in the current period compared to the prior period. The lower level of natural gas transportation cost that OG&E was allowed to recover from its customers decreased the gross margin by approximately $0.4 million in the current period compared to the prior period, as a result of the Acquisition Premium Credit Rider ("APC Rider") and the Gas Transportation Credit Rider ("GTAC Rider"). Kilowatt-hour sales to other utilities and power marketers ("off-system sales") decreased $0.3 million in the current period as compared to the prior period. Although the volume of off-system sales increased in the current period as compared to the prior period, the average price per kilowatt-hour decreased to $2.29 in the current period compared to $6.19 in the prior period.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. In the current period, fuel expense decreased approximately $42.0 million or 33.1 percent primarily due to a 37.7 percent decrease in the average cost of fuel per kilowatt-hour (particularly the cost of natural gas).

In the current period, OG&E's purchased power costs decreased approximately $13.1 million or 17.1 percent due to a 13.0 percent decrease in the volume of purchased energy and a 28.8 percent decrease in the cost of purchased energy.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through automatic fuel adjustment clauses. While the regulatory mechanisms for recovering fuel costs differ in Oklahoma and Arkansas, in both states the costs are passed through to customers with no ultimate benefit or detriment to OG&E. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex. See "Regulation and Rates-Recent Regulatory Matters."

Other operating expenses include operating and maintenance expense, depreciation and amortization, and taxes other than income. OG&E's operating and maintenance expense decreased approximately $7.0 million or 9.8 percent in the current period primarily due to a decrease of approximately $4.2 million in bad debt expense, a decrease of approximately $1.4 million in professional services expense and a decrease of approximately $1.4 million in miscellaneous corporate expenses. Depreciation and amortization expense increased

approximately $0.5 million or 1.6 percent in the current period due to a higher level of depreciable plant. Taxes other than income increased approximately $0.2 million or 1.9 percent in the current period primarily due to higher ad valorem tax accruals.

Enogex

	Three Months Ended March 31	
(Dollars in thousands)	**2002**	2001
Operating revenues	**$ 342,606**	$ 750,537
Gas and electricity purchased for resale	**268,391**	656,235
Natural gas purchases - other	**19,803**	50,542
Gross margin on revenues	**54,412**	43,760
Other operating expenses	**45,444**	45,973
Operating income (loss)	**8,968**	(2,213)
Other income, net	**1,436**	539
EBIT	**$ 10,404**	$ (1,674)
Physical System Supply - MMcfd (a)	**1,696**	1,850
Natural gas processed - MMcfd	**636**	750
Natural gas liquids sold - thousand gallons	**107,563**	114,426
Average sales price per gallon	**$ 0.338**	$ 0.631
Fractionation spread per MMBtu (b)	**$ 0.729**	$ 0.013
Natural gas marketed - Bbtu (c)	**98,300**	83,430
Average sales price per Bbtu	**$ 2.593**	$ 7.108
Power marketed - MWH	**266,913**	310,911
Average sales price per MWH	**$ 26.311**	$ 43.710
Natural gas produced - Mmcfe (d)	**1,296**	1,469
Average sales price per Mcfe (e), net of hedging	**$ 2.350**	$ 8.195

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

Enogex's EBIT for the current period was $10.4 million, which was $12.1 million higher than the prior period. This increase was primarily attributable to increased margins in transportation and storage; gathering and processing; and marketing and trading, offset by reduced margins in exploration and production.

During the current period, the transportation pipeline and storage facilities contributed $10.7 million, or 102.6 percent of the Enogex EBIT, which was an increase of $9.4 million from the prior period. This increased contribution to EBIT is primarily due to increased transportation revenues of $4.7 million which can be partially attributed to a new transportation contract with Cogentrix Energy, Inc., an IPP, which began on January 1, 2002. Also contributing to the increased EBIT was a reduction in fuel expense of $5.9 million associated with operating the pipeline due to lower natural gas prices during the current period compared to the prior period. Partially offsetting these increases to EBIT was a $0.9 million increase in minority interest expense. The remaining $0.3 million decrease to EBIT is due to higher depreciation and amortization expense in the current period.

During the current period, gathering and processing contributed a loss of $0.5 million to the Enogex EBIT, which was an increase of $5.6 million from the prior period. The improvement in EBIT is primarily due to a $4.5 million gain related to more favorable fractionation spreads during the current period. Fractionation spreads are the value of liquids after they are processed out of natural gas, less the price of the gas itself. A significant percentage of Enogex's volumes during the prior period were processed under "keep whole" arrangements. Under these arrangements, and in order to keep its shippers whole on a Btu basis, Enogex was required to replace the Btu value of the liquids with natural gas at market prices. In order to minimize the impact of low fractionation spreads, ethane and propane were rejected whenever possible. In the prior period, 65.1 million gallons were rejected compared to 31.6 million gallons in the current period. The average fractionation spread realized in the current period was $0.729 per MMBtu compared to $0.013 per MMBtu for the prior period. Also contributing to the improved EBIT was a $1.6 million gain resulting from the sale of Enogex's interest in Belvan Corporation, Belvan Limited Partnership and Todd Ranch Limited Partnership in March 2002. Partially offsetting the improvements in EBIT was a $0.5 million decrease to EBIT primarily from lower gathering and processing gross margins resulting from lower sales volumes and prices offset by lower operating expenses in the current period.

During the current period, marketing and trading contributed $0.1 million of the Enogex EBIT, which was an increase of $5.2 million from the prior period. The increased contribution to EBIT is primarily due to increased natural gas sales margins of $5.8 million in the current period due to increased volumes and lower natural gas prices. In the prior period, marketing and trading contributed a loss of $5.1 million to Enogex's EBIT. The trading activities are conducted throughout the year subject to a $4 million annual trading loss limit. The daily loss exposure is measured using value at risk and other quantitative risk measurement techniques. These limits are designed to mitigate the possibility of marketing and trading having a material adverse effect on Enogex's EBIT. Partially offsetting the increased natural gas sales margin was a $0.6 million decrease to EBIT primarily from increased operating expenses in the current period.

During the current period, exploration and production contributed $0.1 million of the Enogex EBIT, which was a decrease of $8.1 million from the prior period. The decreased EBIT is primarily due to a decrease of $6.3 million related to lower natural gas sales caused by lower natural gas prices in the current period. Also contributing to the decreased EBIT were hedging gains of $2.6 million in the prior period which did not occur in the current period. Partially

offsetting these decreases was a $0.8 million increase to EBIT primarily from lower depreciation and amortization expense and lower taxes other than income in the current period.

Liquidity and Capital Requirements

As discussed above, in January 2002, a significant ice storm hit OG&E's service territory and inflicted major damage to the transmission and distribution infrastructure with total expenditures estimated at $136 million. On April 8, 2002, OG&E announced it would request the OCC to include in its existing rate case recovery of these expenditures. The area of damage is within counties that were declared a federal disaster area. Therefore, OG&E is also seeking recovery of a portion of the storm damages from the Federal government with the assistance of the OCC and the Oklahoma Congressional delegation. The expenditures for restoration of the transmission and distribution infrastructure have been capitalized as part of the Company's property, plant and equipment or deferred pending recovery through regulation or other alternatives.

The Company's primary needs for capital are related to replacing or expanding existing facilities in OG&E's electric utility business and replacing or expanding existing facilities at Enogex. Other capital requirements are primarily related to maturing debt, capital and operating lease obligations and unconditional purchase obligations. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings and permanent financings. Capital expenditures for the current period were $87.7 million and were financed with internally generated funds and short-term borrowings.

Management expects that internally generated funds will be adequate during the remainder of 2002 to meet anticipated construction expenditures and maturities of long-term debt. Short-term borrowings will continue to be used to meet temporary cash requirements. OG&E has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time. The

Company has in place lines of credit in the aggregate for up to $310 million, with $15 million expiring on June 6, 2002, $195 million expiring on January 9, 2003, and $100 million expiring on January 15, 2004. In January 2002, the Company's $200 million line of credit was renewed for $195 million. Short-term borrowings will consist of a combination of bank borrowings and commercial paper. The Company's ability to access the commercial paper market could be adversely impacted by a commercial paper ratings downgrade. The line of credit contains ratings triggers that require annual fees and borrowing rates to increase if the Company suffers an adverse ratings impact. The impact of a downgrade would result in an increase in the cost of short-term borrowings of approximately five to 20 basis points, but would not result in any defaults or accelerations as a result of the ratings triggers.

Like any business, the Company is subject to numerous contingencies, many of which are beyond its control. For a discussion of significant contingencies that could affect the Company, reference is made to Part II, Item 1 - "Legal Proceedings" of this Form 10-Q and to "Management's Discussion and Analysis" and Notes 10 and 11 of Notes to the Consolidated Financial Statements in the Company's 2001 Form 10-K.

Critical Accounting Policies and Estimates

The Consolidated Financial Statements and Notes to Consolidated Financial Statements included in this Form 10-Q and in the Company's 2001 Form 10-K contain information that is pertinent to Management's Discussion and Analysis. In preparing these condensed consolidated financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the condensed consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. These assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company has taken conservative positions, where assumptions and estimates are used, in order to minimize the negative financial impact to the Company 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 energy trading contracts, pension plan assumptions, gas storage inventory, unbilled revenue for the electric utility, allowance for uncollectible accounts receivable and contingency reserves.

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

Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized. For a discussion of the pension plan rate assumptions, reference is made to Note 8 of the Consolidated Financial Statements in the Company's 2001 Form 10-K. The assumed return on plan assets is based on management's expectation of the long-term return on plan assets portfolio.

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

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

OG&E reads its customers' meters and sends its bills throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. This unbilled revenue is estimated by adding the amount of electric power generated and purchased less off-system sales and estimated line losses, which results in net kilowatt-hours available for sale for the current period. From this number, the amount of billed kilowatt-hours are deducted to arrive at an estimate of unbilled kilowatt-hours for the period. These unbilled kilowatt-hours are then multiplied by an estimate of the average price to be paid by customers to arrive at unbilled revenue. The estimates that management uses in this calculation could vary from the actual price to be paid by customers, but when consistently applied from period to period, this method should not result in any material differences.

The allowance for uncollectible accounts receivable is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12 month historical average of actual balances written off. To the extent that historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized.

From time to time, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to claims made by third parties or the action of various regulatory agencies. Management consults with counsel and other appropriate experts to assess the claim. If in management's opinion the claim meets the definition of a contingent liability as set forth by generally accepted accounting principles, an estimate is made of the contingent liability and the appropriate accounting entries are reflected in the Company's financial statements.

Regulation and Rates

OG&E's retail electric tariffs in Oklahoma are regulated by the OCC, and in Arkansas by the APSC. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's wholesale electric tariffs, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the Department of Energy has jurisdiction over some of OG&E's facilities and operations.

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

Recent Regulatory Matters

In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of OG&E. In the filing, the OCC Staff requested that OG&E submit information in accordance with OCC minimum standard filing requirements by January 28, 2002 for a test year ending September 30, 2001. On December 14, 2001, OG&E, citing the need for investment in security and system reliability, filed a notice with the OCC of its intent to seek an increase in OG&E's electric rates. On January 28, 2002, OG&E filed testimony with the OCC supporting OG&E's request for a $22 million annual rate increase. If granted, the increase would be the first for OG&E since 1985. Over the past 16 years, OG&E has had annual rate reductions of more than $142 million.

Attempting to make security investments at the proper level, OG&E developed a set of guidelines to arrive at the appropriate steps to minimize long-term or widespread outages, minimize the impact on critical national defense and related customers, maximize the ability to respond to and recover from an attack, minimize the financial impact on OG&E that might be caused by an attack and accomplish these efforts with minimal impact on ratepayers. Initially, approximately $10 million of the rate increase requested by OG&E was to invest in increased security. As described below, OG&E subsequently withdrew its request for the $10 million related to security. The additional $12 million is for investment in increased system reliability and for increased utility costs. OG&E has added new generation capacity to meet growing customer demand and has determined a need to increase expenditures for distribution system reliability that has been brought about, in no small part, by a series of record-breaking storms, including a 1995 windstorm in the Oklahoma City area affecting 175,000 customers, 1999 tornadoes affecting about 150,000 customers and disrupting service at a power plant, July 2000 thunderstorms affecting 110,000 customers, a Christmas 2000 ice storm affecting 140,000 customers, Memorial Day 2001 storms leaving 143,000 customers without power and at least two other storms affecting at least 100,000 customers each.

Additionally, OG&E has experienced an overall increase in operating expenses. As part of it's filing, OG&E sought approval to offer several new rate program choices to customers. One such pilot program involves flat billing. This option would set a customer's bill at a fixed dollar amount and would not change throughout the year regardless of the amount of power consumed. The bill amount would then be adjusted in the following year based on the previous year's usage and other factors. Another proposed rate program, a Green Power option, would involve OG&E contracting with wind generators to purchase a quantity of wind-generated energy, then offering that power to customers. The rate would reflect the higher cost of wind-generated power. Also included in the filing was OG&E's offer to not seek a rate increase for three years. A final order in OG&E's rate case is not expected until later in 2002.

As discussed above, on January 30, 2002, a significant ice storm hit OG&E's service territory and inflicted major damage to the transmission and distribution infrastructure with total expenditures estimated at $136 million. On April 8, 2002, OG&E announced it would request the OCC to withdraw the $10 million increased security portion of OG&E's January request for a $22 million annual rate increase. Instead, OG&E intends to work with the OCC Staff under a

joint filing to determine the appropriate dollar amount for security upgrades. OG&E is requesting the OCC to include in the January 2002 rate case, relief from the estimated $136 million in damages caused by the ice storm.

On May 8, 2002, the OCC ordered a two month delay in the procedural schedule of OG&E's rate case. The delay will allow more time for reporting and auditing the expenditures associated with the ice storm.

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

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

The final action addresses the competitive bid process of OG&E's gas transportation needs following which OG&E's affiliate, Enogex, contracted to provide gas transportation service to all of OG&E's generation plants. In the 1997 Order, the OCC approved a stipulation wherein OG&E agreed to initiate a competitive bidding process for gas transportation service to its gas-fired plants, with the competitive services commencing no later than April 30, 2000. The order also set annual compensation for the transportation services provided by Enogex to OG&E at $41.3 million annually until March 1, 2000, at which time the rate would drop to $28.5 million (reflecting removal of the APC Rider, upon the completion of the recovery from customers of the amortization premium paid by OG&E when it acquired Enogex in 1986) and remain at that level until competitively-bid gas transportation began. In July 1999, OG&E filed an application with the OCC requesting approval of a performance-based rate plan for its Oklahoma retail customers

from April 2000 until the introduction of customer choice for electric power in July 2002. As part of this application, OG&E stated that Enogex had submitted the only viable bid ($33.4 million per year) for gas transportation to OG&E's six gas-fired power plants that were the subject of the competitive bid. As part of its application to the OCC, OG&E offered to discount Enogex's bid from $33.4 million annually to $25.2 million annually. OG&E executed a gas transportation contract with Enogex under which Enogex continues to serve the needs of OG&E's power plants at a price to be paid by OG&E of $33.4 million annually and, if OG&E's proposal had been approved by the OCC, OG&E would have recovered a portion of such amount ($25.2 million) from its customers. OG&E negotiated with the OCC Staff, the Office of the Oklahoma Attorney General and a coalition of industrial customers in an effort to settle all issues (including the competitive bid process) associated with its application for a performance-based rate plan. When these negotiations failed, OG&E withdrew its application, which withdrawal was approved by the OCC in December 1999.

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

State Restructuring Initiatives

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

Arkansas: In April 1999, Arkansas passed a law ("the Restructuring Law") calling for restructuring of the electric utility industry at the retail level. The Restructuring Law, like the

Act, will significantly affect OG&E's future operations. OG&E's electric service area includes parts of western Arkansas, including Fort Smith, the second-largest metropolitan market in the state. The Restructuring Law initially targeted customer choice of electricity providers by January 1, 2002. In February 2001, the Restructuring Law was amended to delay the start date of customer choice of electric providers in Arkansas until October 1, 2003, with the APSC having discretion to further delay implementation to October 1, 2005. The Restructuring Law also provides that utilities owning or controlling transmission assets must transfer control of such transmission assets to an independent system operator, independent transmission company or regional transmission group, if any such organization has been approved by the FERC. OG&E filed preliminary business separation plans with the APSC on August 8, 2000. The APSC has established a timetable to establish rules implementing the Restructuring Law.

Report of Business Segments

The Company's electric utility operations are conducted through OG&E, an operating public utility engaged in the generation, transmission, distribution and sale of electric energy. Energy supply operations are conducted through Enogex. Enogex is engaged in transporting natural gas through its intra-state pipeline to various customers (including OG&E), gathering and processing natural gas, marketing electricity, natural gas and natural gas liquids and investing in the development for and production of natural gas and crude oil. Other Operations primarily include unallocated corporate expenses and interest expense on commercial paper. The following are the results for the Company's business segments.

Three Months Ended March 31, 2002	Electric Utility	Energy Supply	Other Operations	Intersegment	Total
(In thousands)					
Operating revenues	$ 262,083	$ 342,606	$ ---	$ (9,599)(A)	$ 595,090
Fuel	84,992	---	---	(9,079)	75,913
Purchased power	63,843	---	---	---	63,843
Gas and electricity purchased for resale	---	268,391	---	(520)	267,871
Natural gas purchases - other	---	19,803	---	---	19,803
Cost of goods sold	148,835	288,194	---	(9,599)	427,430
Gross margin on revenues	113,248	54,412	---	---	167,660
Other operation and maintenance	64,720	27,453	(3,635)	---	88,538
Depreciation and amortization	30,780	13,787	2,416	---	46,983
Taxes other than income	11,916	4,204	752	---	16,872
Operating income	5,832	8,968	467	---	15,267
Other income (expenses), net	(408)	1,436	13	---	1,041
Earnings before interest and taxes	$ 5,424	$ 10,404	$ 480	$ ---	$ 16,308
Net loss	$ (1,517)	$ (1,281)	$ (6,202)	$ 2,777	$ (6,223)

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

Three Months Ended March 31, 2001	Electric Utility	Energy Supply	Other Operations	Intersegment	Total
(In thousands)					
Operating revenues	$ 326,835	$ 750,537	$ ---	$ (13,785)(A)	$ 1,063,587
Fuel	126,962	---	---	(9,079)	117,883
Purchased power	76,969	---	---	---	76,969
Gas and electricity purchased for resale	---	656,235	---	(4,706)	651,529
Natural gas purchases - other	---	50,542	---	---	50,542
Cost of goods sold	203,931	706,777	---	(13,785)	896,923
Gross margin on revenues	122,904	43,760	---	---	166,664
Other operation and maintenance	71,721	28,390	(2,021)	---	98,090
Depreciation and amortization	30,296	13,287	1,741	---	45,324
Taxes other than income	11,685	4,296	669	---	16,650
Operating income (loss)	9,202	(2,213)	(389)	---	6,600
Other income (expenses), net	(791)	539	2	---	(250)
Earnings before interest and taxes	$ 8,411	$ (1,674)	$ (387)	$ ---	$ 6,350
Net loss	$ (997)	$ (9,615)	$ (14,984)	$ 10,627	$ (14,969)

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Market Risk

Risk Management

The risk management process established by the Company is designed to measure both quantitative and qualitative risks in its businesses. A senior risk management committee has been established to review these risks on a regular basis. The Company is exposed to market risk, including changes in certain commodity prices and interest rates.

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

Interest Rate Risk

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

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

During 2001, the Company entered into two separate interest rate swap agreements: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110 million of 7.30 percent fixed rate debt, due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate ("LIBOR") and (ii) Enogex entered into an interest rate swap agreement, effective July 15, 2001, to convert $200 million of 8.125 percent fixed rate debt due, January 15, 2010, to a variable rate based on LIBOR. On March 1, 2002, Enogex monetized its interest rate swap agreement and received cash of $4.2 million, which will be amortized over the life of the related debt.

On March 4, 2002, Enogex entered into a new interest rate swap agreement to convert $200 million of 8.125 percent fixed rate debt due, January 15, 2010, to a variable rate based on LIBOR.

These interest rate swaps qualified as fair value hedges under SFAS No. 133 and meet all requirements for a determination that there was no ineffective portion as allowed under the shortcut method under SFAS No. 133.

The fair value of long-term debt is estimated based on quoted market prices and management's estimate of current rates available for similar issues. The following table shows the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

(Dollars in millions)	2003	2004	2005	Thereafter	Total	Fair Value at March 31, 2002
Fixed rate debt						
Principal amount...	$ 14.3	$ 53.0	$ 153.0	$ 861.6	$1,081.9	$1,210.2
Weighted-average interest rate....	7.70%	7.22%	7.09%	7.48%	7.37%	---
Variable rate debt						
Principal amount...	---	---	---	$ 442.7	$ 442.7	$ 442.7
Weighted-average interest rate....	---	---	---	4.85%	4.85%	---

Commodity Price Risk

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

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

A sensitivity analysis has been prepared to estimate the commodity price risk exposure to the market risk of the Company's natural gas, natural gas liquids and electricity commodity positions. The Company's daily net commodity position consists of natural gas inventories, purchased electric capacity, commodity purchase and sales contracts and derivative financial and commodity instruments. The fair value of such position is a summation of the fair values calculated for each commodity by valuing each net position at quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in such prices over the next 12 months. The results of this analysis, which may differ from actual results, are as follows at March 31, 2002:

(In thousands)	Trading	Non-Trading
Commodity market risk, net...........	$ 1,244	$ ---

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Reference is made to Item 3 of the Company's 2001 Form 10-K for a description of certain legal proceedings presently pending. There are no new significant cases to report against the Company or its subsidiaries and there have been no material changes in the previously reported proceedings, except as set forth below:

Reference is made to Note 10 of the Company's Consolidated Financial Statements included in Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, for a discussion of the agreements between Central Oklahoma Oil and Gas Corp. ("COOG") and OG&E and between COOG and Enogex. As explained in Note 10, COOG provides gas storage services to OG&E from a gas storage facility (herein, the "Stuart Facility") owned and operated by COOG. In developing the Stuart Facility, COOG obtained permanent financing and issued a note (herein, the "Promissory Note"), originally in the amount of $49.5 million. In connection with the permanent financing, the Company entered into a note purchase agreement, where it agreed, upon the occurrence of a monetary default by COOG on its permanent financing, to purchase the Promissory Note from the holders at a price equal to its unpaid principal amount and interest. In July 1998, and as explained in detail in Note 10, Enogex also agreed to lease additional underground gas storage from COOG at the Stuart Facility, with the additional capacity being developed by COOG. This lease agreement was accounted for as a capital lease, and an asset was recorded for $26.5 million, which is being amortized over 40 years. The lease term is five years and includes seven five-year renewal options. As of December 31, 2001, 2000 and 1999, the capital lease obligation amounted to $9.3 million, $9.8 million and $10.1 million, respectively. As part of the Enogex lease, the Company agreed to make up to a $12 million secured loan to an affiliate of COOG. As part of this agreement, the Company has an $8 million loan outstanding repayable in 2003 which is secured by the assets and stock of COOG. This loan is classified as Other Property and Investments in the accompanying Consolidated Balance Sheets. Disputes arose under the lease agreement between Enogex and COOG and the parties arbitrated these disputes pursuant to the terms of the lease agreement. The arbitration panel rendered a decision on February 8, 2002 ("Arbitration Award"). Pursuant to the Arbitration Award, COOG filed with the arbitration panel a Motion to Reconsider the panel's ruling, which was denied by a majority of the panel. Enogex has instituted proceedings with the District Court of Oklahoma County to have the Arbitration Award confirmed and entered as a judgment of that court.

By letter dated May 9, 2002, COOG advised the holder of its Promissory Note that the Arbitration Award was in excess of $10 million and, in the event the Arbitration Award became a final, non-appealable order, it would constitute an event of default under the loan agreement relating to the Promissory Note. COOG also advised the holder of its Promissory Note that, due to the significant expenses incurred in defending the Arbitration Award, it was unable to make the payment of principal and interest on the Promissory Note due May 1, 2002. As a result, the Company could be required to purchase the Promissory Note at a price equal to its unpaid

principal and interest of approximately $34 million. As the holder of the Promissory Note, the Company would be a secured creditor, with a first mortgage or comparable security interest on all of COOG's assets. OG&E and Enogex have separate rights to purchase the Stuart Facility at prices set by their contracts, which, in the case of Enogex, include the right to offset against such purchase price, among other things, the outstanding amount of the loan from the Company to COOG's affiliate. At the present time, the ultimate resolution of this matter and the actions to be taken by the Company or COOG are not known. However, in light of the Company's ability to become a secured creditor upon the purchase of the Promissory Note and the rights of OG&E and Enogex to purchase the Stuart Facility, the Company does not believe that the ultimate resolution of this matter will have a material adverse effect on its consolidated financial position or results of operations.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits
None

(b) Reports on Form 8-K
The Company filed a Current Report on Form 8-K on February 6, 2002 to report the status of the estimated costs of the January 2002 ice storm.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

OGE ENERGY CORP.
(Registrant)

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

(On behalf of the registrant and in
his capacity as Chief Accounting Officer)

May 15, 2002