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 September 30, 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: 1-12579

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____

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).
Yes _X_ No___

As of October 31, 2003, 86,917,173 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2003

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Item 1. Financial Statements

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2003	December 31, 2002
	(In millions)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 29.2	$ 44.4
Accounts receivable, net	354.8	304.6
Accrued unbilled revenues	58.9	28.2
Fuel inventories	120.7	99.7
Materials and supplies, at average cost	41.8	42.6
Price risk management	39.0	17.1
Pipeline imbalance	46.6	34.3
Accumulated deferred tax assets	11.4	10.9
Fuel clause under recoveries	21.4	14.7
Other	6.3	10.6
Current assets of discontinued operations	---	4.7
Total current assets	730.1	611.8
OTHER PROPERTY AND INVESTMENTS, at cost	28.6	27.2
PROPERTY, PLANT AND EQUIPMENT		
In service	5,589.6	5,469.7
Construction work in progress	47.7	44.8
Other	23.4	30.5
Total property, plant and equipment	5,660.7	5,545.0
Less accumulated depreciation	2,325.7	2,231.4
Net property, plant and equipment	3,335.0	3,313.6
In service of discontinued operations	---	54.2
Less accumulated depreciation	---	11.4
Net property, plant and equipment of discontinued operations	---	42.8
Net property, plant and equipment	3,335.0	3,356.4
DEFERRED CHARGES AND OTHER ASSETS		
Recoverable take or pay gas charges	32.5	32.5
Income taxes recoverable from customers, net	31.8	34.8
Intangible asset - unamortized prior service cost	42.7	42.7
Prepaid benefit obligation	65.5	44.9
Price risk management	18.6	20.1
Other	60.4	80.8
Deferred charges and other assets of discontinued operations	---	0.2
Total deferred charges and other assets	251.5	256.0

TOTAL ASSETS	$ 4,345.2	$ 4,251.4

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

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

	September 30, 2003	December 31, 2002
	(In millions)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 96.8	$ 275.0
Accounts payable	242.9	269.0
Dividends payable	28.7	26.1
Customers' deposits	34.4	33.0
Accrued taxes	22.5	23.6
Accrued interest	28.1	35.7
Tax collections payable	10.2	6.7
Accrued vacation	17.7	16.9
Long-term debt due within one year	61.0	21.0
Price risk management	24.9	13.9
Pipeline imbalance	7.1	9.4
Other	31.2	19.4
Current liabilities of discontinued operations	---	2.0
Total current liabilities	605.5	751.7
LONG-TERM DEBT	1,440.8	1,501.9
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	192.0	184.2
Accumulated deferred income taxes	714.1	627.0
Accumulated deferred investment tax credits	43.3	47.1
Accrued removal obligations, net	113.9	109.3
Price risk management	2.7	0.6
Provision for payments of take or pay gas	32.5	32.5
Other	5.7	4.1
Deferred credits and other liabilities of discontinued operations	---	9.1
Total deferred credits and other liabilities	1,104.2	1,013.9
STOCKHOLDERS' EQUITY		
Common stockholders' equity	614.2	453.5
Retained earnings	654.6	604.7
Accumulated other comprehensive loss, net of tax	(74.1)	(74.3)
Total stockholders' equity	1,194.7	983.9
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 4,345.2	$ 4,251.4

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

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions, except per share data)			
OPERATING REVENUES				
Electric Utility operating revenues	$ 540.3	$ 488.9	$1,230.9	$1,103.2

Natural Gas Pipeline operating revenues	519.7	398.4	1,731.9	1,090.7
Total operating revenues	1,060.0	887.3	2,962.8	2,193.9
COST OF GOODS SOLD				
Electric Utility cost of goods sold	254.3	199.3	634.0	508.6
Natural Gas Pipeline cost of goods sold	467.3	352.2	1,578.0	964.6
Total cost of goods sold	721.6	551.5	2,212.0	1,473.2
Gross margin on revenues	338.4	335.8	750.8	720.7
Other operation and maintenance	90.3	88.9	273.7	270.4
Depreciation	43.5	45.5	133.1	136.7
Impairment of assets	---	---	1.0	---
Taxes other than income	17.3	15.6	51.4	48.7
OPERATING INCOME	187.3	185.8	291.6	264.9
OTHER INCOME (EXPENSE)				
Other income	0.3	0.6	7.0	1.3
Other expense	(2.8)	(1.3)	(6.3)	(2.9)
Net other income (expense)	(2.5)	(0.7)	0.7	(1.6)
INTEREST INCOME (EXPENSE)				
Interest income	0.2	0.5	0.5	1.5
Interest on long-term debt	(18.5)	(21.6)	(56.7)	(65.2)
Interest on trust preferred securities	(4.3)	(4.3)	(13.0)	(13.0)
Allowance for borrowed funds used during construction	0.1	0.1	0.5	0.8
Interest on short-term debt and other interest charges	(1.6)	(2.2)	(5.1)	(6.4)
Net interest expense	(24.1)	(27.5)	(73.8)	(82.3)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	160.7	157.6	218.5	181.0
INCOME TAX EXPENSE	59.4	60.7	80.7	67.2
INCOME FROM CONTINUING OPERATIONS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	101.3	96.9	137.8	113.8
DISCONTINUED OPERATIONS				
Income (loss) from discontinued operations	(0.5)	0.2	1.7	5.1
Income tax expense (benefit)	1.3	(1.9)	2.2	(2.3)
Income (loss) from discontinued operations	(1.8)	2.1	(0.5)	7.4
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	99.5	99.0	137.3	121.2
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING FOR ENERGY TRADING CONTRACTS, NET OF TAX OF $3.7	---	---	(5.9)	---
NET INCOME	$ 99.5	$ 99.0	$ 131.4	$ 121.2
BASIC AVERAGE COMMON SHARES OUTSTANDING	82.4	78.1	80.1	78.0
DILUTED AVERAGE COMMON SHARES OUTSTANDING	82.7	78.1	80.4	78.1
BASIC EARNINGS (LOSS) PER AVERAGE COMMON SHARE				
Income from continuing operations	$ 1.23	$ 1.24	$ 1.72	$ 1.46
Income (loss) from discontinued operations, net of tax	(0.02)	0.03	(0.01)	0.09
Loss from cumulative effect of accounting change, net of tax	---	---	(0.07)	---
NET INCOME	$ 1.21	$ 1.27	$ 1.64	$ 1.55
DILUTED EARNINGS (LOSS) PER AVERAGE COMMON SHARE				
Income from continuing operations	$ 1.22	$ 1.24	$ 1.71	$ 1.46
Income (loss) from discontinued operations, net of tax	(0.02)	0.03	(0.01)	0.09
Loss from cumulative effect of accounting change, net of tax	---	---	(0.07)	---
NET INCOME	$ 1.20	$ 1.27	$ 1.63	$ 1.55
DIVIDENDS DECLARED PER SHARE	$0.3325	$0.3325	$0.9975	$0.9975

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

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

	Nine Months Ended September 30,	
	2003	**2002**
	(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 131.4	$ 121.2
Adjustments to reconcile net income to net cash provided from operating activities		
Loss (income) from discontinued operations	0.5	(7.4)
Cumulative effect of change in accounting principle	5.9	---
Depreciation	133.1	136.7
Impairment of assets	1.0	---
Deferred income taxes and investment tax credits, net	91.5	20.7
Gain on sale of assets	(5.7)	(0.6)
Ineffectiveness of interest rate swap	---	0.2
Price risk management assets	(22.0)	7.5
Price risk management liabilities	12.5	11.4
Other assets	(20.8)	(47.9)
Other liabilities	4.8	(1.5)
Change in certain current assets and liabilities		
Accounts receivable, net	(42.3)	(93.8)
Accrued unbilled revenues	(30.7)	(17.7)
Fuel, materials and supplies inventories	(29.8)	(25.8)
Pipeline imbalance asset	(12.3)	(27.9)
Fuel clause under recoveries	(6.6)	(17.1)
Other current assets	4.3	5.4
Accounts payable	(26.2)	48.8
Customers' deposits	1.3	2.6
Accrued taxes	2.5	77.4
Accrued interest	(7.5)	(11.3)
Fuel clause over recoveries	---	(23.4)
Pipeline imbalance liability	(2.2)	8.2
Other current liabilities	17.9	10.9
Net Cash Provided from Operating Activities	200.6	176.6
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(140.1)	(188.8)
Proceeds from sale of assets	15.7	1.0
Other investing activities	0.3	(0.4)
Net Cash Used in Investing Activities	(124.1)	(188.2)
CASH FLOWS FROM FINANCING ACTIVITIES		
Retirement of long-term debt	(19.0)	(114.0)
(Decrease) increase in short-term debt, net	(178.2)	140.8
Premium on issuance of common stock	144.1	1.5
Distribution to minority interest	(2.5)	---
Dividends paid on common stock	(72.2)	(75.7)
Net Cash Used in Financing Activities	(127.8)	(47.4)
DISCONTINUED OPERATIONS		
Net cash (used in) provided from operating activities	(2.0)	26.9
Net cash provided from investing activities	38.1	11.0
Net cash used in financing activities	---	(1.4)
Net Cash Provided from Discontinued Operations	36.1	36.5
NET DECREASE IN CASH AND CASH EQUIVALENTS	(15.2)	(22.5)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	44.4	37.5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 29.2	$ 15.0

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

OGE ENERGY CORP.
NOTES TO CONDENSED 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 and the Natural Gas Pipeline segments. All significant intercompany transactions have been eliminated in consolidation.

The Electric Utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through Oklahoma Gas and Electric Company (“OG&E”) and are subject to regulation by the Oklahoma Corporation Commission (“OCC”), the Arkansas Public Service Commission (“APSC”) and the Federal Energy Regulatory Commission (“FERC”). OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area.

The Natural Gas Pipeline segment is conducted through Enogex Inc. and its subsidiaries (“Enogex”) and consists of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing and trading of natural gas. Enogex’s focus is to utilize its gathering, processing, transportation and storage capacity and execute physical, financial and service transactions to capture revenues across different commodities, locations, or time periods. The vast majority of Enogex’s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership, Enogex also owns a controlling interest in and operates the Ozark Gas Transmission System (“Ozark”), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex was previously engaged in the exploration and production of natural gas, however, this portion of Enogex’s business, along with interests in certain gas gathering and processing assets in Texas, were sold in 2002 and in the first quarter of 2003 and are reported in the condensed consolidated financial statements as discontinued operations.

The Company allocates operating costs to its affiliates based on several factors. Operating costs directly related to specific affiliates are assigned to those affiliates. Where more than one affiliate benefits from certain expenditures, the costs are shared between those affiliates receiving the benefits. Operating costs incurred for the benefit of all affiliates are allocated among the affiliates, based primarily upon head-count, occupancy, usage or the “Distragas” method. The Distragas method is a three-factor formula that uses an equal weighting of payroll,

operating income and assets. The Company believes this method provides a reasonable basis for allocating common expenses.

Basis of Presentation

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 fairly present the consolidated financial position of the Company at September 30, 2003 and December 31, 2002, the results of its operations for the three and nine months ended September 30, 2003 and 2002, and the results of its cash flows for the nine months ended September 30, 2003 and 2002, have been included and are of a normal recurring nature.

Due to seasonal fluctuations and other factors, the operating results for the three and nine months ended September 30, 2003 are not necessarily indicative of the results that may be expected for the year ending December 31, 2003 or for any future period. 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, 2002.

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 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 September 30, 2003 and December 31, 2002, regulatory assets of approximately $58.5 million and approximately $63.9 million, respectively, are being amortized and reflected in rates charged to customers over periods of up to 20 years. At September 30, 2003 and December 31, 2002, regulatory liabilities of approximately $113.9 million and approximately $109.3 million, respectively, have been reclassified from Accumulated Depreciation in accordance with SFAS No. 143, “Accounting for Asset Retirement Obligations.”

OG&E initially records 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:

(In millions)	**September 30,**	December 31,

	2003	2002
Regulatory Assets		
Income taxes recoverable from customers, net	**$ 31.8**	$ 34.8
Unamortized loss on reacquired debt	**22.4**	23.3
January 2002 ice storm	**3.6**	5.4
Miscellaneous	**0.7**	0.4
Total Regulatory Assets	**$ 58.5**	$ 63.9
Regulatory Liabilities		
Accrued removal obligations, net	**$ 113.9**	$ 109.3
Total Regulatory Liabilities	**$ 113.9**	$ 109.3

Income taxes recoverable from customers represent income tax benefits previously used to reduce OG&E's revenues. These amounts are being recovered in rates as the temporary differences that generated the income tax benefit turn around. The provisions of SFAS No. 71 allowed 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 Condensed Consolidated Balance Sheets in the line item, "Income Taxes Recoverable from Customers, Net."

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 and liabilities; the financial effects of which could be significant.

Use of Estimates

In preparing the 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. Changes to these assumptions and estimates could have a material effect on the Company's condensed consolidated financial statements. In management's opinion, the areas of the Company where the most significant judgment is exercised are in the valuation of pension plan assumptions, impairment estimates, contingency reserves, unbilled revenue for OG&E, the allowance for uncollectible accounts receivable and the valuation of energy purchase and sale contracts and natural gas storage inventory.

Allowance for Uncollectible Accounts Receivable

For OG&E, all customer balances are written off if not collected within six months after the account is finalized. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. The allowance for uncollectible accounts receivable for Enogex is established on a case-by-case basis when the Company believes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was approximately $4.5 million and $13.6 million at September 30, 2003 and December 31, 2002, respectively.

Impairment of Assets

The Company assesses potential impairments of assets when there is evidence that events or changes in circumstances indicate that an asset's carrying value may not be recoverable. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset.

Income Taxes

The Company files consolidated income tax returns. Income taxes are allocated to each affiliate 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.

Cash and Cash Equivalents

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

Revenue Recognition

OG&E

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

Enogex

The Company recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with natural gas liquids is recognized when the production is processed and sold. Substantially all of OGE Energy Resources, Inc.'s ("OERI") natural gas and power marketing contracts qualify as derivatives and, therefore, are accounted for at fair value as prescribed in SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Under fair value accounting, fixed-price forwards, swaps, options, futures and other financial instruments with third parties are recorded at estimated fair market values, net of reserves, with the corresponding market changes in fair value recognized in earnings and offsetting amounts recorded as Price Risk Management assets and liabilities in the accompanying Condensed Consolidated Balance Sheets. See Note 2 for a further discussion.

Automatic Fuel Adjustment Clauses

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

Fuel Inventories

OG&E

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. These inventories are accounted for under the last-in, first-out ("LIFO") cost method. The estimated replacement cost of fuel inventories was higher than the stated LIFO cost by approximately $5.1 million and $7.0 million at September 30, 2003 and December 31, 2002, respectively, based on the average cost of fuel purchased.

Enogex

Effective January 1, 2003, natural gas storage inventory used in OERI's business activities are accounted for at the lower of cost or market in accordance with the guidance in Emerging Issues Task Force ("EITF") Issue No. 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities," which resulted in the rescission of EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," as amended. Prior to January 1, 2003, this inventory was accounted for on a fair value accounting basis utilizing a gas index that in management's opinion approximated the current market value of natural gas in that region as of the Balance Sheet date. On April 1, 2003, natural gas storage inventory used in OERI's business activities began to be accounted for under SFAS No. 133. In order to minimize risk, OERI enters into contracts or hedging instruments to hedge the fair value of this inventory. For any contracts that qualify for hedge accounting under SFAS No. 133, the hedged portion of the inventory is recorded at fair value with an offsetting gain or loss recorded currently in earnings. The fair value of the hedging instrument is also recorded on the books of the Company as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. At September 30, 2003, the Company had all natural gas inventory hedged with qualified fair value hedges under SFAS No. 133. As part of its recurring business activity, OERI injects and withdraws natural gas under the terms of storage capacity contracts; the amount of natural gas inventory was approximately $56.8 million and $32.9 million at September 30, 2003 and December 31, 2002, respectively. See Note 2 for a further discussion.

Stock-Based Compensation

Pursuant to the provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," the Company has elected to continue using the intrinsic value method of accounting for its stock-based employee compensation plans in accordance with Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees." Accordingly, the Company has not recognized compensation expense for its stock-based awards to employees.

The following table reflects pro forma net income and income per average common share had the Company elected to adopt the fair value based method of SFAS No. 123:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	**2003**	2002
	(In millions, except per share data)			
Net income, as reported	**$ 99.5**	$ 99.0	**$ 131.4**	$ 121.2
Add:				
Stock-based employee compensation expense included				

in reported net income, net of related tax effects	---	---	---	---
Deduct:				
Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	**0.4**	0.3	**1.1**	0.8
Pro forma net income	**$ 99.1**	$ 98.7	**$ 130.3**	$ 120.4
Income per average common share				
Basic - as reported	**$ 1.21**	$ 1.27	**$ 1.64**	$ 1.55
Basic - pro forma	**$ 1.20**	$ 1.26	**$ 1.63**	$ 1.54
Diluted - as reported	**$ 1.20**	$ 1.27	**$ 1.63**	$ 1.55
Diluted - pro forma	**$ 1.20**	$ 1.26	**$ 1.62**	$ 1.54

Reclassifications

Certain prior year amounts have been reclassified on the condensed consolidated 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. SFAS No. 143 affects the Company's accrued plant removal costs for generation, transmission, distribution and processing facilities 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. 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 is 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 consolidated 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. As described below, amounts recovered from ratepayers related to estimated asset retirement obligations recorded as a liability in Accumulated Depreciation were reclassified as a regulatory liability in the first quarter of 2003.

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 adoption of SFAS No. 143, the Company was required to quantify the amount of asset retirement costs previously recovered from ratepayers 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 Condensed Consolidated Balance Sheet. At September 30, 2003, the regulatory liability for accrued removal obligations, net was approximately $113.9 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 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 is 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 consolidated financial position or results of operations.

In October 2002, the EITF reached a consensus on certain issues covered in EITF 02-3. One consensus of EITF 02-3 requires that all mark-to-market gains and losses, whether realized or unrealized, on financial derivative contracts as defined in SFAS No. 133 be shown net in the Income Statement for financial statements issued for periods beginning after December 15, 2002, with reclassification required for prior periods presented. The Company adopted this consensus

effective January 1, 2003 and the application of this consensus did not have a material impact on its consolidated financial position or results of operations as this consensus supports the Company's historical presentation of financial derivative contracts.

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

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure — an amendment of FASB Statement No. 123." SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation which includes the prospective method, modified prospective method and retroactive restatement method. SFAS No. 148 also amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. Adoption of the annual disclosure and voluntary transition requirements of SFAS No. 148 is required for annual financial statements issued for fiscal years ending after December 15, 2002. Adoption of the interim disclosure requirements of SFAS No. 148 is required for interim periods beginning after December 15, 2002. Pursuant to the provisions of SFAS No. 123, the Company has elected to continue using the intrinsic value method of accounting for its stock-based employee compensation plans in accordance with APB 25. However, the Company has included the required disclosures under SFAS No. 148 in Note 1.

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 consolidated 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 moves 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 will adopt this new interpretation effective December 31, 2003 and the adoption of this new interpretation is not expected to have a material impact on its consolidated 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 consolidated financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity." SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. The requirements of this statement apply to an

issuer's classification and measurement of freestanding financial instruments, including those that comprise more than one option or forward contract. This statement does not apply to features that are embedded in a financial instrument that are not a derivative in its entirety. This statement also addresses questions about the classification of certain financial instruments that embody obligations to issue equity shares. SFAS No. 150 requires that instruments that are redeemable upon liquidation or termination of an issuing subsidiary that has a limited life are considered mandatorily redeemable shares under SFAS No. 150 in the consolidated financial statements of the parent. Accordingly, these noncontrolling interests are required to be classified as liabilities under SFAS No. 150. All provisions of this statement, except the provisions related to a limited-life subsidiary, are effective for financial instruments entered into or modified after May 31, 2003, and otherwise are effective at the beginning of the first interim period beginning after June 15, 2003. Companies are not required to recognize noncontrolling interests of a limited-life subsidiary as a liability in the consolidated financial statements and should continue to account for these interests as minority interests until the FASB considers resulting implementation issues associated with the measurement and recognition guidance for these noncontrolling interests. Except for the provisions related to a limited-life subsidiary, 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 consolidated financial position or results of operations. The Company does not expect that the provisions related to a limited-life subsidiary will have a material impact on its consolidated financial position or results of operations.

3. Price Risk Management Assets and Liabilities

Non-Trading Activities

The Company periodically utilizes derivative contracts to manage exposure to unfavorable changes in commodity prices, as well as to reduce exposure to adverse interest rate fluctuations. During the nine months ended September 30, 2003 and 2002, the Company's use of non-trading price risk management instruments primarily involved the use of interest rate swap agreements to hedge the Company's exposure to interest rate risk by converting a portion of the Company's fixed rate debt to a floating rate. These agreements involve the receipt of fixed rate amounts in exchange for floating rate interest payments over the life of the agreement without an exchange of the underlying principal amount. In addition, the Company utilized certain fixed price swap instruments to hedge the price to be received for fuel authorized to be recovered from customers as well as to hedge portions of the Company's exposure to natural gas liquids prices and natural gas storage activities.

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, any gain or loss deferred in Accumulated Other Comprehensive Income is recognized currently in earnings. The Company's interest rate swap agreements have been designated as fair value hedges 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.

At September 30, 2003, the Company had outstanding cash flow hedges and approximately a $0.2 million after tax gain was included in Accumulated Other Comprehensive Loss. At December 31, 2002, the Company had no outstanding cash flow hedges, and no amounts were included in Accumulated Other Comprehensive Loss related to cash flow hedges.

Trading Activities

The Company, through its subsidiary, OERI, engages in energy trading activities primarily related to the purchase and sale of natural gas. Contracts utilized in these activities generally include forward swap contracts as well as over-the-counter and exchange traded futures and options. Under the guidance provided by SFAS No. 133, financial instruments that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as Price Risk Management assets or liabilities in the accompanying Condensed Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement. Unrealized gains and losses from changes in the market value of open contracts are included in Natural Gas Pipeline operating revenues in the Condensed Consolidated Statements of Income. Energy trading contracts resulting in delivery of a commodity that meet the requirements of EITF Issue No. 99-19, "Reporting Revenues Gross as a Principal or Net as an Agent," are included as sales or purchases in the accompanying Condensed Consolidated Statements of Income depending on whether the contract relates to the sale or purchase of the commodity. See Note 2 for a further discussion of the accounting for the Company's energy trading activities.

4. Comprehensive Income

The components of total comprehensive income for the three and nine months ended September 30, 2003 and 2002, respectively, are as follows:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions)	**2003**	2002	**2003**	2002
Net income	**$ 99.5**	$ 99.0	**$ 131.4**	$121.2
Other comprehensive income, net of tax:				
Deferred hedging gains	**0.5**	---	**0.2**	0.1
Total comprehensive income	**$ 100.0**	$ 99.0	**$ 131.6**	$121.3

Accumulated other comprehensive loss at both September 30, 2003 and December 31, 2002 included approximately a $74.3 million after tax loss ($121.3 million pre-tax) related to a minimum pension liability adjustment. The Company's actuarial consultants review the funded status of the pension plan at year end. Any increases or decreases in the minimum pension liability will be reflected in Other Comprehensive Income or Loss in the fourth quarter. Also included at September 30, 2003 was approximately a $0.2 million after tax gain related to outstanding cash flow hedges.

5. Discontinued Operations

On March 25, 2002, Enogex entered into an Agreement of Sale and Purchase with West Texas Gas, Inc. to sell all of its interests in Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership ("Belvan") for approximately $9.8 million. The effective date of the sale was January 1, 2002 and the closing occurred on March 28, 2002. The Company recognized approximately a $1.6 million after tax gain related to the sale of these assets.

On August 5, 2002, Enogex entered into an Agreement of Sale and Purchase with Chesapeake Exploration Limited Partnership to sell all of its exploration and production assets located in Oklahoma, Texas, Arkansas and Mississippi for approximately $15.0 million. The effective date of the sale was July 1, 2002 and the closing occurred on September 19, 2002. The Company recognized approximately a $2.3 million after tax loss related to the sale of these assets.

On November 14, 2002, Enogex entered into an Agreement of Sale and Purchase with Quicksilver Resources, Inc. to sell all of its exploration and production assets located in Michigan for approximately $32.0 million. The effective date of the sale was July 1, 2002 and the closing occurred on December 2, 2002. The Company recognized approximately a $2.9 million after tax gain related to the sale of these assets.

During the third quarter of 2002, the Company decided to sell all of its interests in the NuStar Joint Venture ("NuStar"). On January 23, 2003, Enogex entered into an Agreement of Sale and Purchase with Benedum Gas Partners, L.P. to sell all of the interests of its subsidiary, Enogex Products Corporation, in the west Texas properties consisting of NuStar, which has operations consisting of the extraction and sale of natural gas liquids, for approximately $37.0 million. The effective date of the sale was January 1, 2003 and the closing occurred on February 18, 2003. The Company recognized approximately a $1.4 million after tax gain related to the sale of these assets in the first quarter of 2003. The final accounting for the NuStar sale was completed in the third quarter of 2003 which resulted in an additional charge of approximately $0.2 million after tax which was recorded in the third quarter of 2003.

The condensed consolidated financial statements of the Company have been restated to reflect Enogex's exploration and production assets, NuStar and Belvan, all of which were part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses, assets, liabilities and cash flows of the exploration and production assets, NuStar and Belvan have been excluded from the respective captions in the condensed consolidated financial statements and have been reported as "Current Assets of Discontinued Operations", "Net Property, Plant and Equipment of Discontinued Operations", "Deferred Charges and Other Assets of Discontinued Operations", "Current Liabilities of Discontinued Operations", "Deferred Credits and Other Liabilities of Discontinued Operations", "Income from Discontinued Operations" and "Net Cash Provided from Discontinued Operations."

Summarized financial information for the discontinued operations is as follows:

CONDENSED CONSOLIDATED STATEMENTS OF INCOME DATA

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions)	**2003**	2002	**2003**	2002
Operating revenues from discontinued operations	**$ ---**	$ 19.2	**$ 7.8**	$ 60.4
Income (loss) from discontinued operations before taxes	**$ (0.5)**	$ 0.2	**$ 1.7**	$ 5.1

CONDENSED CONSOLIDATED BALANCE SHEET DATA

(In millions)	**September 30, 2003**	December 31, 2002
Accounts receivable, net	**$ ---**	$ 4.1
Other	---	0.6
Total current assets of discontinued operations	**$ ---**	$ 4.7
Plant in service of discontinued operations	---	54.2
Less accumulated depreciation	---	11.4
Net property, plant and equipment of discontinued operations	**$ ---**	$ 42.8
Total deferred charges and other assets of discontinued operations	**$ ---**	$ 0.2
Accounts payable	---	1.1
Accrued taxes	---	0.4
Other	---	0.5
Total current liabilities of discontinued operations	**$ ---**	$ 2.0
Total deferred credits and other liabilities of discontinued operations	**$ ---**	$ 9.1

6. Asset Disposals

On August 2, 2002, Ozark, in which an Enogex subsidiary owns a 75 percent interest, entered into an Agreement of Sale and Purchase with CenterPoint Energy Gas Transmission Co. to sell approximately 29 miles of transmission lines of the Ozark pipeline located in Pittsburg and Latimer counties in Oklahoma for approximately $10.0 million. On November 18, 2002, the Company received FERC approval for the closing, which occurred on January 6, 2003. The Company recognized approximately a $5.3 million pre-tax gain in the first quarter of 2003 related to the sale of these assets, which is recorded in Other Income in the accompanying Condensed Consolidated Statements of Income. These assets were part of the Natural Gas Pipeline segment.

On July 15, 2003, the Company entered into an Agreement of Sale and Purchase to sell the Company's aircraft for approximately $5.8 million. During the second quarter of 2003, the Company recognized a pre-tax impairment loss of $1.0 million in Other Operations related to the Company's aircraft. The impairment resulted from plans to dispose of the aircraft at a price below the carrying amount. The fair value of the aircraft was determined based on a third-party evaluation. The closing was completed in August 2003 and the Company recognized approximately a $0.1 million pre-tax loss related to the sale of the aircraft. The aircraft was part of Other Operations.

7. Supplemental Cash Flow Information

Non-cash financing activities for the nine months ended September 30, 2003 and 2002, included approximately a $1.8 million decrease and an $8.8 million increase, respectively, related to the change in the fair value of the interest rate swap agreements and the corresponding change in long-term debt.

Non-cash financing activities for the nine months ended September 30, 2003 included approximately $8.6 million related to the Company issuing new common stock to satisfy the common stock dividend requirements of the Company's stock plans rather than purchasing the common stock on the open market.

In connection with the filing in the third quarter of 2003 of the Company's consolidated income tax returns for 2002, the Company elected to change its tax method of accounting related to the capitalization of costs for self-constructed assets to another method prescribed in the Treasury regulations. The accounting method change is for income tax purposes only. For financial accounting purposes, the only change 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 the Company's current federal and state income tax liability for 2002 and all estimated payments made for 2002 have been or will be refunded. As a result of this tax net operating loss, tax credits associated with Enogex's natural gas production

were not realized and resulted in approximately $1.8 million in higher income tax expense in discontinued operations.

8. Common Stock

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

In April 2003, the Company filed a Form S-3 Registration Statement to register 7,000,000 shares of the Company's common stock pursuant to the Automatic Dividend Reinvestment and Stock Purchase Plan (the "Plan"). Under the terms of the Plan, the Company may accept requests for optional investments in amounts greater than $0.1 million per year and may offer a discount of up to three percent from current market prices. This program allows the Company to sell additional common stock at a lower discount than that normally incurred in a secondary equity offering. During the nine months ended September 30, 2003, the Company issued 615,721 shares at a discount of 1.75 percent and 1,147,903 shares of common stock at a discount of 1.50 percent pursuant to the Plan. In October 2003, the Company issued 364,722 shares of common stock at a discount price of 1.50 percent. Also as part of the Plan, the Company issued 746,585 shares and 214,516 shares of common stock at no discount during the nine months ended September 30, 2003 and 2002, respectively.

For the nine months ended September 30, 2003 and 2002, respectively, there were 45,034 shares and 10,199 shares of new common stock issued pursuant to the Stock Incentive Plan, which related to exercised stock options.

9. Earnings per Share

Outstanding shares for purposes of basic and diluted earnings per share were calculated as follows:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2003	2002	**2003**	2002
	(In millions)			
Average Common Shares Outstanding				
Basic average common shares outstanding	**82.4**	78.1	**80.1**	78.0
Effect of dilutive securities:				
Employee stock options and unvested stock grants	**0.1**	--	**0.1**	0.1
Contingently issuable shares (Company's Annual Incentive Compensation Plan)	**0.2**	--	**0.2**	--
Diluted average common shares outstanding	**82.7**	78.1	**80.4**	78.1

Approximately 1.9 million shares and 2.2 million shares for the three months ended September 30, 2003 and 2002, respectively, and approximately 2.0 million shares and 1.4 million

shares for the nine months ended September 30, 2003 and 2002, respectively, related to outstanding employee stock options, were not included in the calculation of diluted earnings per average common share because the effect of including those shares is anti-dilutive as the exercise price of the stock options exceeded the average common stock market price during the respective period.

10. Long-Term Debt

Interest Rate Swap Agreements

At September 30, 2003 and December 31, 2002, the Company had three outstanding interest rate swap agreements: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate ("LIBOR") and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert $100.0 million each of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR.

These interest rate swaps qualified as fair value hedges under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards.

At September 30, 2003 and December 31, 2002, the fair values pursuant to the interest rate swaps were approximately $14.2 million and $15.9 million, respectively, and were included in non-current Price Risk Management assets in the accompanying Condensed Consolidated Balance Sheets. A corresponding net increase of approximately $14.2 million and $15.9 million was reflected in Long-Term Debt at September 30, 2003 and December 31, 2002, respectively, as these fair value hedges were effective at September 30, 2003 and December 31, 2002.

S-3 Filing

On April 17, 2003, OG&E filed a Form S-3 Registration Statement pursuant to which it may offer from time to time up to $200.0 million aggregate principal amount of OG&E’s unsecured senior notes.

Security Ratings

On January 15, 2003, Standard & Poor’s Ratings Services (“Standard & Poor’s”) lowered the credit ratings of OGE Energy Corp.’s senior unsecured debt from A- to BBB. Standard & Poor’s also lowered the credit ratings of OG&E’s and Enogex’s senior unsecured debt from A- to BBB+. OGE Energy Corp.’s short-term commercial paper ratings were affirmed at A-2. 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 consolidated financial position or results of operations.

On February 5, 2003, Moody’s Investors Service (“Moody’s”) lowered the credit ratings of OGE Energy Corp.’s senior unsecured debt to Baa1 from A3, OG&E’s senior unsecured debt to A2 from A1 and Enogex’s senior unsecured debt to Baa3 from Baa2. OGE Energy Corp.’s short-term commercial paper rating was unchanged at P-2. 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 consolidated financial position or results of operations. As a result of Enogex’s rating being lowered to Baa3, OGE Energy Corp. was required to issue a $5.0 million guarantee on OERI's behalf for a counterparty. At September 30, 2003, there is no outstanding liability balance related to this guarantee.

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.

11. Short-Term Debt

Consolidated short-term debt of approximately $96.8 million and $275.0 million, respectively, was outstanding at September 30, 2003 and December 31, 2002. The following table shows the Company’s lines of credit in place at September 30, 2003. Short-term borrowings will consist of a combination of bank borrowings and commercial paper.

Lines of Credit *(In millions)*

Entity	Amount	Maturity
OGE Energy Corp. (A)	$ 200.0	January 8, 2004
	100.0	January 15, 2004
	15.0	April 6, 2004
OG&E	100.0	June 26, 2004
Total	$ 415.0	

(A) The lines of credit at OGE Energy Corp. are used to back up the Company's commercial paper borrowings, which were approximately $63.0 million at September 30, 2003. No borrowings were outstanding at September 30, 2003 under any of the lines of credit shown above; however, $8.0 million of the $15.0 million line of credit above is supported by a letter of credit described in Note 13.

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

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

12. Report of Business Segments

The Company’s Electric Utility operations are conducted through OG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy. The

Company’s Natural Gas Pipeline operations are conducted through Enogex. Enogex is engaged in the transportation and storage of natural gas, the gathering and processing of natural gas and the marketing and trading of natural gas. Enogex also has been involved in investing in the development for and production of natural gas and crude oil, which investments Enogex sold during 2002. Other Operations primarily includes unallocated corporate expenses and interest expense on commercial paper and the Trust Originated Preferred Securities. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. The following tables are a summary of the results of the Company’s business segments for the three and nine months ended September 30, 2003 and 2002.

Three Months Ended September 30, 2003	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 540.3**	**$ 533.3**	**$ ---**	**$ (13.6)**	**$1,060.0**
Fuel	**181.9**	**---**	**---**	**(11.8)**	**170.1**
Purchased power	**84.2**	**---**	**---**	**---**	**84.2**
Gas and electricity purchased for resale	**---**	**460.0**	**---**	**(1.8)**	**458.2**
Natural gas purchases - other	**---**	**9.1**	**---**	**---**	**9.1**
Cost of goods sold	**266.1**	**469.1**	**---**	**(13.6)**	**721.6**
Gross margin on revenues	**274.2**	**64.2**	**---**	**---**	**338.4**
Other operation and maintenance	**71.5**	**22.1**	**(3.3)**	**---**	**90.3**
Depreciation	**29.9**	**11.0**	**2.6**	**---**	**43.5**
Taxes other than income	**12.0**	**4.6**	**0.7**	**---**	**17.3**
Operating income	**160.8**	**26.5**	**---**	**---**	**187.3**
Other income	**---**	**0.1**	**0.2**	**---**	**0.3**
Other expense	**(0.9)**	**(0.5)**	**(1.4)**	**---**	**(2.8)**
Interest income	**0.4**	**0.2**	**4.5**	**(4.9)**	**0.2**
Interest expense	**(9.9)**	**(9.8)**	**(9.5)**	**4.9**	**(24.3)**
Income tax expense (benefit)	**55.3**	**6.3**	**(2.2)**	**---**	**59.4**
Income (loss) from continuing operations	**$ 95.1**	**$ 10.2**	**$ (4.0)**	**$ ---**	**$ 101.3**
Loss from discontinued operations	**$ ---**	**$ (1.8)**	**$ ---**	**$ ---**	**$ (1.8)**
Net income (loss)	**$ 95.1**	**$ 8.4**	**$ (4.0)**	**$ ---**	**$ 99.5**

(A) Beginning with the first quarter of 2002, Natural Gas Pipeline's operations consisted of three related businesses: Transportation and Storage, Gathering and Processing and Marketing and Trading. The following is supplemental Natural Gas Pipeline information.

Three Months Ended September 30, 2003	Transportation and Storage	Gathering and Processing	Marketing and Trading	Eliminations	Total
(In millions)					
Operating revenues	**$ 62.4**	**$ 117.3**	**$ 435.9**	**$ (82.3)**	**$ 533.3**
Operating income (loss)	**$ 21.0**	**$ 6.2**	**$ (0.7)**	**$ ---**	**$ 26.5**

Three Months Ended September 30, 2002	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 488.9	$ 412.5	$ ---	$ (14.1)	$ 887.3
Fuel	140.4	---	---	(8.1)	132.3
Purchased power	66.9	---	---	---	66.9
Gas and electricity purchased for resale	---	344.4	---	(6.0)	338.4
Natural gas purchases - other	---	13.9	---	---	13.9
Cost of goods sold	207.3	358.3	---	(14.1)	551.5
Gross margin on revenues	281.6	54.2	---	---	335.8
Other operation and maintenance	68.9	23.6	(3.6)	---	88.9
Depreciation	30.9	12.1	2.5	---	45.5
Taxes other than income	11.6	3.4	0.6	---	15.6
Operating income	170.2	15.1	0.5	---	185.8
Other income	0.1	0.5	---	---	0.6
Other expense	(0.7)	(0.1)	(0.5)	---	(1.3)
Interest income	0.3	0.2	4.8	(4.8)	0.5

Interest expense	(10.5)	(12.4)	(9.9)	4.8	(28.0)
Income tax expense (benefit)	61.0	1.3	(1.6)	---	60.7
Income (loss) from continuing operations	$ 98.4	$ 2.0	$ (3.5)	$ ---	$ 96.9
Income from discontinued operations	$ ---	$ 2.1	$ ---	$ ---	$ 2.1
Net income (loss)	$ 98.4	$ 4.1	$ (3.5)	$ ---	$ 99.0

(A) Beginning with the first quarter of 2002, Natural Gas Pipeline's operations consisted of three related businesses: Transportation and Storage, Gathering and Processing and Marketing and Trading. The following is supplemental Natural Gas Pipeline information.

Three Months Ended September 30, 2002	Transportation and Storage	Gathering and Processing	Marketing and Trading	Eliminations	Total
(In millions)					
Operating revenues	$ 101.7	$ 46.0	$ 312.1	$ (47.3)	$ 412.5
Operating income (loss)	$ 16.1	$ 1.2	$ (2.2)	$ ---	$ 15.1

Nine Months Ended September 30, 2003	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$1,230.9**	**$1,786.1**	**$ ---**	**$ (54.2)**	**$2,962.8**
Fuel	**448.8**	**---**	**---**	**(33.0)**	**415.8**
Purchased power	**218.2**	**---**	**---**	**---**	**218.2**
Gas and electricity purchased for resale	**---**	**1,556.3**	**---**	**(21.2)**	**1,535.1**
Natural gas purchases - other	**---**	**42.9**	**---**	**---**	**42.9**
Cost of goods sold	**667.0**	**1,599.2**	**---**	**(54.2)**	**2,212.0**
Gross margin on revenues	**563.9**	**186.9**	**---**	**---**	**750.8**
Other operation and maintenance	**218.3**	**66.9**	**(11.5)**	**---**	**273.7**
Depreciation	**91.7**	**33.2**	**8.2**	**---**	**133.1**
Impairment of assets	**---**	**---**	**1.0**	**---**	**1.0**
Taxes other than income	**35.7**	**13.4**	**2.3**	**---**	**51.4**
Operating income	**218.2**	**73.4**	**---**	**---**	**291.6**
Other income	**0.5**	**5.9**	**0.6**	**---**	**7.0**
Other expense	**(2.1)**	**(2.0)**	**(2.2)**	**---**	**(6.3)**
Interest income	**0.5**	**0.8**	**14.3**	**(15.1)**	**0.5**
Interest expense	**(30.0)**	**(30.1)**	**(29.3)**	**15.1**	**(74.3)**
Income tax expense (benefit)	**67.4**	**20.0**	**(6.7)**	**---**	**80.7**
Income (loss) from continuing operations	**$ 119.7**	**$ 28.0**	**$ (9.9)**	**$ ---**	**$ 137.8**
Loss from discontinued operations	**$ ---**	**$ (0.5)**	**$ ---**	**$ ---**	**$ (0.5)**
Income (loss) before cumulative effect of change in accounting principle	**$ 119.7**	**$ 27.5**	**$ (9.9)**	**$ ---**	**$ 137.3**
Cumulative effect on prior years of change in valuation of energy trading contracts, net of tax	**$ ---**	**$ (5.9)**	**$ ---**	**$ ---**	**$ (5.9)**
Net income (loss)	**$ 119.7**	**$ 21.6**	**$ (9.9)**	**$ ---**	**$ 131.4**

(A) Beginning with the first quarter of 2002, Natural Gas Pipeline's operations consisted of three related businesses: Transportation and Storage, Gathering and Processing and Marketing and Trading. The following table is supplemental Natural Gas Pipeline information.

Nine Months Ended September 30, 2003	Transportation and Storage	Gathering and Processing	Marketing and Trading	Eliminations	Total

(In millions)

Operating revenues	**$ 185.1**	**$ 392.9**	**$1,514.1**	**$ (306.0)**	**$1,786.1**
Operating income	**$ 48.9**	**$ 14.5**	**$ 10.0**	**$ ---**	**$ 73.4**

Nine Months Ended September 30, 2002	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$1,103.2	$1,125.9	$ ---	$ (35.2)	$2,193.9
Fuel	338.2	---	---	(25.6)	312.6
Purchased power	196.0	---	---	---	196.0
Gas and electricity purchased for resale	---	918.8	---	(9.6)	909.2
Natural gas purchases - other	---	55.4	---	---	55.4
Cost of goods sold	534.2	974.2	---	(35.2)	1,473.2
Gross margin on revenues	569.0	151.7	---	---	720.7
Other operation and maintenance	209.1	71.4	(10.1)	---	270.4
Depreciation	91.9	37.3	7.5	---	136.7
Taxes other than income	35.2	11.5	2.0	---	48.7
Operating income	232.8	31.5	0.6	---	264.9
Other income	0.4	0.9	---	---	1.3
Other expense	(2.2)	(0.1)	(0.6)	---	(2.9)
Interest income	1.2	1.1	14.2	(15.0)	1.5
Interest expense	(30.4)	(38.0)	(30.4)	15.0	(83.8)
Income tax expense (benefit)	74.1	(1.0)	(5.9)	---	67.2
Income (loss) from continuing operations	$ 127.7	$ (3.6)	$ (10.3)	$ ---	$ 113.8
Income from discontinued operations	$ ---	$ 7.4	$ ---	$ ---	$ 7.4
Net income (loss)	$ 127.7	$ 3.8	$ (10.3)	$ ---	$ 121.2

(A) Beginning with the first quarter of 2002, Natural Gas Pipeline’s operations consisted of three related businesses: Transportation and Storage, Gathering and Processing and Marketing and Trading. The following table is supplemental Natural Gas Pipeline information.

Nine Months Ended September 30, 2002	Transportation and Storage	Gathering and Processing	Marketing and Trading	Eliminations	Total
(In millions)					
Operating revenues	$ 325.5	$ 131.3	$ 881.3	$ (212.2)	$1,125.9
Operating income (loss)	$ 36.2	$ (2.7)	$ (2.0)	$ ---	$ 31.5

13. Commitments and Contingencies

Except as set forth below, the circumstances set forth in Note 15 to the Company’s Consolidated Financial Statements included in the Company’s Form 10-K for the year ended December 31, 2002 and in the Notes to the Company’s Condensed Consolidated Financial Statements included in its Form 10-Q for the quarters ended March 31, 2003 and June 30, 2003, appropriately represent, in all material respects, the current status of any material commitments and contingent liabilities.

Agreement with Colorado Interstate Gas Company

In December 2002, Enogex entered into a Precedent Agreement with Colorado Interstate Gas Company (“CIG”) regarding reservation of capacity on a proposed interstate gas pipeline (the “Cheyenne Plains Pipeline”). If completed, the Cheyenne Plains Pipeline would provide interstate gas transportation services in the states of Wyoming, Colorado and Kansas with a capacity of 560,000 decatherms/day (“Dth/day”). Under the Precedent Agreement, Enogex bid to reserve 60,000 Dth/day of capacity on the proposed pipeline for 10 years and two months. Such reservation would result in Enogex having access to significant additional natural gas supplies in the areas to be served by the proposed pipeline. Subject to regulatory and other approvals, CIG is proposing an in-service date of August 31, 2005.

On May 20, 2003, Cheyenne Plains filed its initial certificate applications with the FERC, including its proposed tariff for the pipeline, as well as certain environmental filings. On July 7, 2003, Enogex filed a motion to intervene, stating certain objections involving Cheyenne Plains' proposed treatment of reservation fees and creditworthiness requirements. Enogex participated in a FERC technical conference with Cheyenne Plains and other interveners in August 2003. The parties reached agreement on the issues raised regarding the proposed tariff provisions.

Guarantees

During the normal course of business, Enogex issues guarantees on behalf of its subsidiaries for the purpose of securing credit for certain business activities. These guarantees are for payment when due of amounts payable by its subsidiaries under various agreements with counterparties. At September 30, 2003, accounts payable supported by guarantees was approximately $47.9 million. Since these guarantees by Enogex represent security for payment of payables obtained in the normal course of its subsidiaries' business activities, the Company, on a consolidated basis, does not assume any additional liability as a result of this arrangement.

OGE Energy Corp. has issued a $5.0 million guarantee on behalf of OERI and a $15.0 million guarantee on behalf of Enogex Inc. for the purpose of securing credit for certain business activities. These guarantees are for payment when due of amounts payable by OERI and Enogex Inc. under various agreements with counterparties. At September 30, 2003, there are no accounts payable supported by these guarantees. Since these guarantees by OGE Energy Corp. represent security for payment of payables obtained in OERI's and Enogex Inc.'s business activities, the Company, on a consolidated basis, does not assume any additional liability as a result of this arrangement.

The Company has issued an $8.0 million standby letter of credit to an insurance company, Energy Insurance Bermuda Ltd. Mutual Business Program No. 19 ("MBP 19"), for the benefit of insuring parts of the Company's property and liability insurance programs. MBP 19 was established to provide $15.0 million worth of property and liability insurance for the Company. The $8.0 million letter of credit was issued to provide protection for MBP 19 in case of large

insurance claim losses. At September 30, 2003, there were no drawings against this letter of credit. This letter of credit renews automatically on an annual basis.

At September 30, 2003, in the event Moody's or Standard & Poor's were to lower Enogex's senior unsecured debt rating to a below investment grade rating, Enogex would be required to post approximately $6.4 million of collateral to satisfy its obligation under its financial and physical contracts.

Firm Transportation Contract with Calpine Energy Services, L.P.

In 2000, Enogex entered into long-term firm transportation contracts with an independent power producer relating to a plant to be built in Wagoner County, Oklahoma. Effective July 1, 2000, the contracts were assigned to Calpine Energy Services, L.P. ("Calpine Energy"). In February 2002, Enogex requested a prepayment from Calpine Energy due to Calpine falling below the contractual creditworthiness criteria set forth in the transportation contracts. Calpine Energy refused to pay, for the months of March 2002 through June 2002, the monthly demand fees pursuant to the transportation contracts on grounds of an alleged force majeure event and also refused to make any prepayments as requested. Enogex also made a demand on Calpine Corporation, as guarantor, relating to Calpine Energy's failure to make the required prepayment and demand payments. The parties entered into a letter agreement dated June 2002, whereby Calpine Energy paid 50 percent of the demand fees for the period beginning July 1, 2002 and continuing through October 31, 2002 and prepaid, on a monthly basis, 50 percent of the monthly demand payment. For the periods after October 31, 2002, Calpine Energy paid the entire monthly demand fee. In Enogex's judgment, the amount of demand revenues owing at September 30, 2003, was approximately $3.4 million, which amount had not been recognized in revenues or earnings on the Company's financial statements.

In September 2002, Calpine Energy and Calpine Corporation filed a declaratory judgment action in the United States District Court for the Northern District of Oklahoma. Calpine Energy sought a declaratory judgment that its failure to obtain permits was a force majeure event under the contract and therefore demand charges were not due and owing; and, that Enogex had no reasonable ground to question its creditworthiness under the contracts. Enogex answered and filed a counterclaim in October 2002. Enogex denied that the declaratory judgment requested was proper and sought, under the counterclaim, an award based on breach of the contracts and the guarantee.

After participating in a court ordered mediation on August 18, 2003, the parties reached a settlement of the pending issues on September 29, 2003. The terms of the settlement obligated Calpine Energy to make a nonrefundable payment to Enogex in the amount of $3.0 million and to maintain a prepayment. Enogex agreed to apply a credit of $1.0 million to the final two months' demand charges under the transportation contract. On September 30, 2003, the parties filed a Joint Stipulation of Dismissal with the trial court. On October 14, 2003, Enogex received payment of the settlement amount from Calpine Energy. As a result of this settlement, the Company recorded $2.0 million of the settlement payment as revenue in the third quarter.

Pending Acquisition of Power Plant

On August 18, 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the 520 MW NRG McClain Station (the "McClain Plant"). The acquisition of this interest in the McClain Plant would constitute an acquisition of new generation under the recent OCC settlement order. The purchase price for the interest in the plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. See Note 14 for a further discussion.

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 condensed consolidated financial statements. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. This assessment of currently pending or threatened lawsuits is subject to change.

14. Rate Matters and Regulation

Regulation and Rates

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

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's assets or income for affiliate transactions.

On October 11, 2002, OG&E, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to a settlement (the "Settlement Agreement") of OG&E'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 OG&E's Oklahoma customers which went into effect January 6, 2003; (ii) recovery by OG&E, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) recovery by OG&E, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through OG&E's rider for sales to other utilities and power marketers; (iv) OG&E to acquire electric generating capacity of not less than 400 megawatts ("MW") to be integrated into OG&E's generation system. Key portions of the Settlement Agreement are described in detail in Note 16 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2002.

As part of the Settlement Agreement, OG&E 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. On April 29, 2003, OG&E filed an application with the OCC in which OG&E advised the OCC that after careful consideration competitive bidding for gas transportation was rejected in favor of a new intrastate firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of OG&E's natural gas fired generation plants. A hearing is scheduled to be held in November 2003 and an OCC order in the case is expected either later in 2003 or early in 2004.

On September 15, 2003, OG&E 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 lists the following, among others, as major issues to be addressed in its application: (i) the acquisition of a generation facility 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, OG&E filed a request with the OCC to increase its rates by approximately $91 million annually. The increase is intended to pay for its acquisition of the McClain Plant, allow for investment in electric system reliability and address rising business costs. The rate plan would reduce rates for schools and more than 80,000 small businesses and non-profit organizations.

Pending Acquisition of Power Plant

On August 18, 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the McClain Plant. The acquisition of this interest in the McClain Plant would constitute an acquisition of new generation under the OCC settlement order discussed above. The purchase price for the interest in the plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. The McClain Plant includes 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 provides that, unless extended, either party has the right to terminate the contract if the closing does not occur on or before December 1, 2003. Because the

current owner of the McClain Plant has filed for bankruptcy protection, the acquisition also is subject to approval by the bankruptcy court. As part of the bankruptcy approval process, NRG McClain LLC's interest in the plant was subject to an auction process and on October 28, 2003, the bankruptcy court approved the sale of NRG McClain LLC's interest in the plant to OG&E. Several parties have filed interventions at the FERC opposing OG&E'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. OG&E believes that its application meets the standards under Section 203 set forth by the FERC and that its application will be approved in the near future.

Following the acquisition, OG&E expects to operate the plant in accordance with a joint ownership and operating agreement with the OMPA that is in the process of being negotiated. Under this agreement, OG&E would operate the facility, and OG&E 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 would be shared in proportion to the respective ownership interests. OG&E expects to utilize its portion of the output, 400 MWs, to serve its native load. As indicated above, OG&E filed with the OCC on October 31, 2003, a request to increase its rates to its Oklahoma customers to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. As provided in its most recent rate settlement with the OCC, pending approval of the request to increase base rates to recover the investment in the plant, OG&E will have the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition, 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 OG&E's request, all prudently incurred costs accrued through the regulatory asset within the 12-month period will be included in OG&E's prospective cost of service.

As part of its most recent rate settlement with the OCC, OG&E undertook to acquire electric generating capacity of not less than 400 MWs. The acquisition of a 77 percent interest in the McClain Plant would constitute an acquisition of such generation under the recent OCC settlement order. OG&E expects this new generation 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 OG&E because OG&E's rates would not need to be reduced to accomplish these savings. PowerSmith has filed an application with the OCC seeking to compel OG&E to continue purchasing power from PowerSmith's qualified cogeneration facility under the Public Utility Regulatory Policies Act of 1978 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 OG&E and PowerSmith or (ii) the avoided cost of the McClain Plant. OG&E 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. To the extent PowerSmith ultimately were successful, it would reduce OG&E's ability to realize the targeted $75 million of savings to its Oklahoma customers over a three-year period.

As indicated above, the decision of OG&E with respect to the purchase of this new generation will be subject to a review by the OCC as a part of a general rate case for the purpose of determining the level of just and reasonable costs associated with the new generation to be included in customers' rates. The OCC's review is expected to include, but not be limited to, an analysis and review of the alternatives to purchasing the new generation, the amount paid for such new generation and the level of capacity purchases. OG&E will provide monthly reports, for a period of 36 months after the acquisition, to the OCC Staff, documenting and providing proof of savings experienced by OG&E's customers. In the event OG&E is unable to demonstrate at least $75.0 million in savings to its customers during this 36-month period, OG&E 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.

In the event OG&E does not acquire the new generation by December 31, 2003, the settlement order requires OG&E 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 OG&E 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.

OG&E expects to fund the acquisition with a combination of a capital contribution from the Company, funded in part by the Company's recent equity issuance, and the issuance of long-term debt.

Security Enhancements

On August 14, 2002, OG&E filed a report with the OCC outlining proposed expenditures and related actions for security enhancement. Attempting to make security investments at the proper level, OG&E has developed a set of guidelines intended to minimize long-term or widespread outages, minimize the impact on critical national defense and related customers, maximize the ability to respond to and recover from an attack, minimize the financial impact on OG&E that might be caused by an attack and accomplish these efforts with minimal impact on ratepayers. The OCC Staff retained a security expert to review the report filed by OG&E. Thereafter, on October 17, 2003, the OCC issued a notice of inquiry seeking comments from the regulated industry for the establishment of guidelines for the protection of critical infrastructure and key assets. OG&E currently expects that hearings will be held in early 2004.

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 OG&E to reflect 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 was to remove approximately $10.7 million annually from the amount being recovered by OG&E from its Oklahoma customers in current rates.

In June 2001, the OCC approved a stipulation (the "Stipulation") to the competitive bid process of OG&E's gas transportation service from Enogex. The Stipulation directed OG&E 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 OG&E'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.

OG&E's Generation Efficiency Performance Rider ("GEP Rider") expired in June 2002. The GEP Rider was established initially in 1997 in connection with OG&E's 1996 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. In June 2000 the OCC made modifications to the GEP Rider which 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.

FERC Section 311 Rate Case

In December 2001, Enogex made its filing at the FERC under Section 311 of the Natural Gas Policy Act to establish rates and a default processing fee and to address various other issues for the combined Enogex and Transok L.L.C. pipeline systems, effective January 1, 2002, the date that these systems began operating as a single Enogex pipeline system. The FERC Staff, Enogex and the active intervening parties held extensive settlement discussions. Enogex

negotiated a settlement of the case with the interveners and, on March 5, 2003, filed a Stipulation and Agreement of Settlement and related documents with the FERC to resolve all issues in dispute in Docket No. PR02-10-000. By Order dated May 9, 2003, the FERC accepted the settlement agreement and entered its order modifying Enogex's Statement of Operating Conditions ("SOC"). The FERC Order required Enogex to modify its SOC to eliminate the priority for scheduling and curtailment purposes for interruptible dedicated gas customers. As ordered, Enogex filed a revised SOC on May 22, 2003. By filings on June 3 and June 9, 2003, respectively, Apache Corporation and the Oklahoma Independent Petroleum Association sought rehearing as to the elimination of the priority for dedicated gas. The FERC issued a tolling order on July 9, 2003 but has not issued an order on the merits. The settlement included a fee to be assessed under certain market conditions to process customer gas gathered behind processing plants so that it meets pipeline gas quality Btu standards and can be redelivered to interstate pipelines (default processing fee). The settlement also approved a monthly low flow meter charge of $200 (offset in any month by the transportation revenues generated by gas through the meter). Pursuant to Enogex's SOC, if Enogex's annual processing gross margin exceeds a $28 million threshold, Enogex is required to record certain obligations. During the third quarter of 2003, the Company established a reserve, based on projected future market conditions, to cover any such obligations. During the first nine months of 2003, the Company has recognized net revenue of approximately $3.0 million for default processing fees and approximately $0.6 million of low flow meter charges.

State Restructuring Initiatives

Oklahoma

As previously reported, the Electric Restructuring Act of 1997 (the "1997 Act") was 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 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, 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. In the 2003 legislative session, Senate Bill 383 was introduced to repeal the 1997 Act. The 2003 legislative session ended without any further action to repeal the 1997 Act. It is unknown at this time whether the bill will be passed into law. 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. OG&E incurred approximately $2.4 million in transition costs necessary to carry out its responsibilities associated with efforts to implement retail open access. OG&E's request to recover these costs is currently being processed by the APSC. The APSC is expected to schedule a hearing early in 2004.

15. 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 that have significantly changed since December 31, 2002:

	September 30, 2003		December 31, 2002	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 43.4**	**$ 43.4**	$ 21.4	$ 21.4
Interest Rate Swaps	**14.2**	**14.2**	15.9	15.9
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 27.6**	**$ 27.6**	$ 14.6	$ 14.6

The carrying value of the financial instruments on the accompanying Condensed Consolidated Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company's interest rate swaps and energy trading contracts was determined primarily based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties and the potential impact of liquidating the position in an orderly manner over a reasonable period of time.

16. Subsequent Event

In October 2003, as a result of an ongoing initiative to improve asset utilization in the Natural Gas Pipeline segment, the Company concluded that certain underutilized compression assets may no longer be required to meet the Company's future business needs. As a result, the Company anticipates recording a fourth quarter impairment charge of approximately $7.5 million to $10.0 million related to these compression assets. The Company anticipates rationalizing these assets within a two to three year period depending on market conditions.

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 Natural Gas Pipeline segments.

The Electric Utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through Oklahoma Gas and Electric Company ("OG&E") and are subject to regulation by the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area.

The Natural Gas Pipeline segment is conducted through Enogex Inc. and its subsidiaries ("Enogex") and consists of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing and trading of natural gas (collectively, the "pipeline businesses"). Enogex's focus is to utilize its gathering, processing, transportation and storage capacity and execute physical, financial and service transactions to capture revenues across different commodities, locations, or time periods. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership, Enogex also owns a controlling interest in and operates the Ozark Gas Transmission System ("Ozark"), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex was previously engaged in the exploration and production of natural gas; however, this portion of Enogex's business, along with interests in certain gas gathering and processing assets in Texas, were sold in 2002 and in the first quarter of 2003 and are reported in the condensed consolidated financial statements as discontinued operations.

Company Strategy

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

The Company's revised business strategy will utilize the diversified asset position of OG&E and Enogex to provide energy products and services to customers primarily in the south central United States. The Company will focus on those products and services with limited or manageable commodity exposure. The Company intends for OG&E to continue as an integrated utility engaged in the generation, transmission and the distribution of electricity and to represent over time approximately 70 percent of the Company's consolidated assets. The remainder of the Company's consolidated assets will be in Enogex's pipeline businesses. In addition to the incremental growth opportunities that Enogex provides, the Company believes that Enogex's risk management capabilities, commercial skills and market information provide value to all of the Company's businesses. Federal regulation in regard to the operations of the wholesale power market may change with the proposed Standard Market Design initiative 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, OG&E plans on increasing its investment and growing earnings largely through the acquisition of a merchant power plant. As discussed in more detail below, on August 18, 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the 520 MW NRG McClain Station (the "McClain Plant"). OG&E has filed with the OCC to increase base rates to recover its investment in, and operating expenses of, this power plant and expects that customers should realize overall lower rates. OG&E expects that the lower rates will be realized due to fuel savings from the increased efficiency of this new plant, elimination of an existing qualified cogeneration and small power production producers' contract ("QF contract") pursuant to which OG&E currently acquires a portion of the power it delivers to its customers and termination of a purchased power contract.

The Company will continue to review all of the supply alternatives to replace expiring QF contracts that minimize the total cost of generation to our customers. Unless extended by OG&E, 540 MWs of QF contracts will expire over the next one to five years. Accordingly, OG&E will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in projected natural gas prices, OG&E will include the feasibility of constructing additional base load coal-fired units in its build options.

Enogex initiated a program in 2002 to improve its financial profile and performance. As a part of this program, Enogex has sold assets and received net sales proceeds of approximately $101.3 million, reduced debt during 2002 by approximately $128.5 million or 17 percent, reduced its number of employees by approximately 12 percent and reorganized its operations. In addition to improving its earnings, Enogex will continue to take actions to reduce its exposure to commodity prices by, among other things, mitigating its exposure to keep whole processing arrangements and reducing earnings volatility. While the Company believes substantial progress has been achieved, substantial opportunities remain. Enogex expects to continue reviewing its work processes, rationalizing assets, negotiating contracts with better terms for both new

contracts and for the replacement of expiring contracts and reducing costs to further improve its cash flow and net income, and will pursue opportunities for organic growth.

In addition to these ongoing efforts, in 2003 the Company began a major upgrade of the information systems that is expected to be substantially completed by the third quarter of 2004. The Company believes that these upgrades will be a major step towards obtaining the data required for it to realize the available opportunities on its assets, provide improved customer service and enable management to more accurately determine the earnings potential of its assets.

Other efforts at Enogex during 2003 have included improvements to its two storage fields. The improvement project at Greasy Creek is intended to reduce potential gas migration, while the improvement project at the newly-acquired Stuart Facility is intended to eliminate water encroachment in the field. To date, expenditures on the projects have not been material and the Company does not expect that the remaining expenditures will be material.

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in "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; the Company's ability and the ability of its subsidiaries to obtain financing on favorable terms; prices of electricity, natural gas and natural gas liquids, each on a stand-alone basis and in relation to each other; business conditions in the energy industry; competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company; unusual weather; 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; and the other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission, including Exhibit 99.01 to the Company's Form 10-K for the year ended December 31, 2002.

Overview

General

The following discussion and analysis presents factors which affected the Company's consolidated results of operations for the three and nine months ended September 30, 2003 as compared to the same periods in 2002 and the Company's consolidated financial position at September 30, 2003. The following information should be read in conjunction with the Condensed Consolidated Financial Statements and Notes thereto and the Company's Form 10-K

for the year ended December 31, 2002. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

Enogex previously was engaged in the exploration and production of natural gas (the "E&P business"). Since January 1, 2002, Enogex has sold all of its E&P business along with certain gas gathering and processing assets that were owned by Enogex through its interest in the NuStar Joint Venture ("NuStar") and its interest in Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership ("Belvan"). As required by accounting principles generally accepted in the United States, these dispositions have been reported as discontinued operations for the three and nine months ended September 30, 2003 and 2002 in the condensed consolidated financial statements.

Operating Results

The Company reported net income of $99.5 million and $99.0 million for the three months ended September 30, 2003 and 2002, respectively, and net income of $131.4 million and $121.2 million for the nine months ended September 30, 2003 and 2002, respectively. The Company reported diluted earnings per share of $1.20 for the three months ended September 30, 2003 as compared to $1.27 for the same period in 2002 and diluted earnings per share of $1.63 for the nine months ended September 30, 2003 as compared to $1.55 for the same period in 2002. The decrease in earnings per share for the three months ended September 30, 2003 as compared to the same period in 2002 was primarily due to the issuance of common stock in the third quarter to help fund OG&E's pending power plant acquisition as net income increased for the three months ended September 30, 2003 as compared to the same period in 2002. The increase in net income for the three months ended September 30, 2003 as compared to the same period in 2002 was primarily due to better operating performance resulting from higher gross margins on revenues ("gross margin") in all of Enogex's businesses, increased levels of firm transportation revenues, improved processing results, the negotiation of both new contracts and replacements for expiring contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas and lower interest expenses at the holding company. These increases were partially offset by lower earnings at OG&E. The increase in net income for the nine months ended September 30, 2003 as compared to the same period in 2002 was primarily due to better operating performance resulting from higher gross margins in all of Enogex's businesses, improved management of pipeline system fuel, increased levels of firm transportation revenues, improved processing results, the negotiation of both new contracts and replacements for expiring contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas, the assistance of default processing fees and lower interest expenses at the holding company. These increases were partially offset by lower earnings at OG&E. The Company's results for the three months ended September 30, 2003 and 2002 include a loss of $0.02 per share and earnings of $0.03 per share, respectively, from the discontinued operations discussed above. The Company's results for the nine months ended September 30, 2003 and 2002 include a loss of $0.01 per share and earnings of $0.08 per share, respectively, from the discontinued operations discussed above. See "Enogex — Discontinued Operations" for a further discussion.

OG&E reported net income of approximately $95.1 million, or $1.15 per share, for the three months ended September 30, 2003 compared with net income of approximately $98.4 million, or $1.26 per share, for the same period in 2002. The decrease in net income was primarily attributable to lower electric rates due to the January 2003 rate reduction and lower recoveries of fuel costs from Arkansas customers partially offset by stronger weather-related demand and customer growth in OG&E's service territory.

Enogex's operations, including discontinued operations, reported net income of approximately $8.4 million, or $0.10 per share, for the three months ended September 30, 2003 compared with net income of approximately $4.1 million, or $0.05 per share, for the same period in 2002. This improvement was primarily attributable to better operating performance resulting from higher gross margins in all of Enogex's businesses, increased levels of firm transportation revenues, improved processing results, the negotiation of both new contracts and replacements for expiring contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas, lower net interest expense and lower operating and maintenance expenses.

As stated above, Enogex's E&P business, its interest in NuStar and its interest in Belvan have been reported as discontinued operations for the three months ended September 30, 2003 and 2002 in the condensed consolidated financial statements as these assets have been sold. The Company's results for the three months ended September 30, 2003 and 2002 include a net loss of approximately $1.8 million, or $0.02 per share, and net income of approximately $2.1 million, or $0.03 per share, respectively, from the discontinued operations discussed above. This decrease was primarily attributable to the sale of Enogex's E&P business and NuStar during 2002 and in the first quarter of 2003, higher income tax expense due to tax credits from Enogex's E&P business not being realized as a result of a tax accounting method change and recording an additional charge related to the sale of NuStar during the third quarter of 2003. See "Enogex — Discontinued Operations" for a further discussion.

The results of the holding company reflect a loss of $0.05 per share for the three months ended September 30, 2003 compared to a loss of $0.04 per share for the three months ended September 30, 2002.

OG&E reported net income of approximately $119.7 million, or $1.49 per share, for the nine months ended September 30, 2003 compared with net income of approximately $127.7 million, or $1.64 per share, for the same period in 2002. The decrease in net income was primarily attributable to lower electric rates due to the January 2003 rate reduction and higher operating and maintenance expenses partially offset by stronger weather-related demand and customer growth in OG&E's service territory.

Enogex's operations, including discontinued operations, reported net income of approximately $21.6 million, or $0.27 per share, for the nine months ended September 30, 2003 compared with net income of approximately $3.8 million, or $0.04 per share, for the same period in 2002. This improvement was primarily attributable to better operating performance resulting from higher gross margins in all of Enogex's businesses, improved management of pipeline system fuel, increased levels of firm transportation revenues, the assistance of default processing fees, the negotiation of both new contracts and replacements of expiring contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas, gains from asset sales, lower net interest expense and lower operating and maintenance expenses.

As stated above, Enogex's E&P business, its interest in NuStar and its interest in Belvan have been reported as discontinued operations for the nine months ended September 30, 2003 and 2002 in the condensed consolidated financial statements as these assets have been sold. The Company's results for the nine months ended September 30, 2003 and 2002 include a net loss of approximately $0.5 million, or $0.01 per share, and net income of approximately $7.4 million, or $0.09 per share, respectively, from the discontinued operations discussed above. This decrease was attributable to the sale of Enogex's E&P business, NuStar and Belvan during 2002 and in the first quarter of 2003, higher income tax expense due to tax credits from Enogex's E&P business not being realized as a result of a tax accounting method change and recording an additional charge related to the sale of NuStar during the third quarter of 2003. See "Enogex — Discontinued Operations" for a further discussion.

The results of the holding company reflect a loss of $0.13 per share for both the nine months ended September 30, 2003 and 2002 primarily due to lower interest expenses.

Regulatory Considerations

On October 11, 2002, OG&E, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to a settlement (the "Settlement Agreement") of OG&E'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 OG&E's Oklahoma customers which went into effect January 6, 2003; (ii) recovery by OG&E, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) recovery by OG&E, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through OG&E's rider for sales to other utilities and power marketers ("off-system sales"); (iv) OG&E to acquire electric generating capacity ("New Generation") of not less than 400 MWs to be integrated into OG&E's generation system.

OG&E expects that the New Generation will provide savings, over a three-year period, in excess of $75 million. If OG&E is unable to demonstrate at least $75 million in savings, OG&E will be required to credit to its Oklahoma customers any unrealized savings below $75 million. In the event OG&E does not acquire the New Generation by December 31, 2003, OG&E will be required 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 OG&E 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 amount to Oklahoma customers will be deducted in the determination of the $75.0 million

targeted savings. Reference is made to Note 14 of Notes to Condensed Consolidated Financial Statements in this report and to Note 16 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2002 for a further discussion of the Settlement Agreement and of other recent actions relating to OG&E's rates.

On September 15, 2003, OG&E 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 lists the following, among others, as major issues to be addressed in its application: (i) the acquisition of a generation facility 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, OG&E filed a request with the OCC to increase its rates by approximately $91 million annually. The increase is intended to pay for its acquisition of the McClain Plant, allow for investment in electric system reliability and address rising business costs. The rate plan would reduce rates for schools and more than 80,000 small businesses and non-profit organizations.

Pending Acquisition of Power Plant

On August 18, 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the 520 MW McClain Plant. The acquisition of this interest in the McClain Plant would constitute an acquisition of new generation under the OCC settlement order discussed above. The purchase price for the interest in the plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. The McClain Plant includes 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 provides that, unless extended, either party has the right to terminate the contract if the closing does not occur on or before December 1, 2003. Because the current owner of the McClain Plant has filed for bankruptcy protection, the acquisition also is subject to approval by the bankruptcy court. As part of the bankruptcy approval process, NRG McClain LLC's interest in the plant was subject to an auction process and on October 28, 2003, the bankruptcy court approved the sale of NRG McClain LLC's interest in the plant to OG&E. Several parties have filed interventions at the FERC opposing OG&E'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. OG&E believes that its application meets the standards under Section 203 set forth by the FERC and that its application will be approved in the near future.

Following the acquisition, OG&E expects to operate the plant in accordance with a joint ownership and operating agreement with the OMPA that is in the process of being negotiated. Under this agreement, OG&E would operate the facility, and OG&E 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 would be shared in proportion to the respective ownership interests. OG&E expects to utilize its portion of the output, 400 MWs, to serve its native load. As indicated above, OG&E filed with the OCC on October 31, 2003, a request to increase its rates to its Oklahoma customers to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. As provided in its most recent rate settlement with the OCC, pending approval of the request to increase base rates to recover, among other things, the investment in the plant, OG&E will have the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition, 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 OG&E's request, all prudently incurred costs accrued through the regulatory asset within the 12-month period will be included in OG&E's prospective cost of service. See "Electric Competition; Regulation" for a further discussion.

OG&E 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 OG&E due to the significant problems faced by California in its electric deregulation efforts and other factors, significant changes are possible, which could significantly change the manner in which OG&E conducts its business. These developments at the federal and state levels are described in more detail below under "Electric Competition; Regulation."

Outlook

General

While the Company has recorded earnings of $1.63 per diluted share through the first nine months of 2003, the Company expects full-year earnings to be at the upper end of the $1.40 to $1.50 per share range for 2003 based on a number of factors expected in the fourth quarter. These factors include a revised net income outlook for Enogex from $18 million to $20 million to $20 million to $22 million, the impact of an increased number of shares outstanding, the $25 million electric rate reduction and higher expenses at OG&E and an impairment charge at Enogex of approximately $7.5 million to $10.0 million associated with the write-down of the value of certain natural gas compression assets, identified during October, for probable sale or other means of disposal in the future. The 2003 outlook includes expected net income of between $112 million and $118 million at OG&E and between $20 million and $22 million at Enogex, while the holding company will likely post a net loss of between $13 million and $14 million

For 2004, the Company expects improved performance from Enogex while at OG&E, financial performance will depend on regulatory relief. Absent any rate relief, earnings at OG&E would be expected to be lower. The consolidated earnings guidance is $1.40 to $1.50 per share, excluding any relief that might come from requested electric rate increases at OG&E. The 2004 outlook includes expected net income of between $109 million and $113 million at OG&E and between $25 million and $29 million at Enogex, while the holding company will likely post a net

loss of approximately $12 million. The Company has assumed approximately 87.2 million average common shares outstanding for 2004.

Dividend Policy

The Company's dividend policy is determined by the Board of Directors and is based on numerous factors, including management's estimate of the long-term earnings power of its businesses. The target payout ratio for the Company is to pay out as dividends approximately 75

percent of its earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of our shareholder base, our financial position, our growth targets, the composition of our assets and investment opportunities. While the dividend payout ratio is expected to exceed the target payout ratio in 2003, management, after considering estimates of future earnings and numerous other factors, expects at this time that it will continue to recommend to the Board of Directors a continuance of the current dividend rate.

Asset Disposals

Enogex sold its interest in NuStar for approximately $37.0 million in February 2003. The Company recognized approximately a $1.4 million after tax gain related to the sale of these assets in the first quarter of 2003. The final accounting for the NuStar sale was completed in the third quarter of 2003 which resulted in an additional charge of approximately $0.2 million after tax which was recorded in the third quarter of 2003. These items are recorded in Income from Discontinued Operations in the accompanying Condensed Consolidated Statements of Income. These assets were part of the Natural Gas Pipeline segment.

Enogex sold approximately 29 miles of transmission lines of the Ozark pipeline, in which an Enogex subsidiary owns a 75 percent interest, located in Pittsburg and Latimer counties in Oklahoma for approximately $10.0 million in January 2003. The Company recognized approximately a $5.3 million pre-tax gain related to the sale of these assets, which is recorded in Other Income in the accompanying Condensed Consolidated Statements of Income. These assets were part of the Natural Gas Pipeline segment.

The Company sold its aircraft for approximately $5.8 million in August 2003. The Company recognized approximately a $0.1 million pre-tax loss related to the sale of the aircraft. The aircraft was part of Other Operations.

Results of Operations

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions, except per share data)	**2003**	2002	**2003**	2002
Operating income	**$ 187.3**	$ 185.8	**$ 291.6**	$ 264.9
Net income	**$ 99.5**	$ 99.0	**$ 131.4**	$ 121.2
Basic average common shares outstanding	**82.4**	78.1	**80.1**	78.0
Diluted average common shares outstanding	**82.7**	78.1	**80.4**	78.1
Basic earnings per average common share	**$ 1.21**	$ 1.27	**$ 1.64**	$ 1.55
Diluted earnings per average common share	**$ 1.20**	$ 1.27	**$ 1.63**	$ 1.55
Dividends declared per share	**$ 0.3325**	$ 0.3325	**$ 0.9975**	$ 0.9975

In reviewing its consolidated operating results, the Company believes that it is appropriate to focus on operating income as reported in its Condensed Consolidated Statements of Income. Operating income was approximately $187.3 million and $185.8 million for the three months ended September 30, 2003 and 2002, respectively. Operating income was approximately

$291.6 million and $264.9 million for the nine months ended September 30, 2003 and 2002, respectively. These amounts exclude the results of Enogex's E&P business, NuStar and Belvan, which as explained above, were sold in 2002 and in the first quarter of 2003 and which are reported as discontinued operations. See "Enogex — Discontinued Operations" below for a further discussion.

Operating Income by Business Segment

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2003**	2002	**2003**	2002
OG&E (Electric Utility)	**$ 160.8**	$ 170.2	**$ 218.2**	$ 232.8
Enogex (Natural Gas Pipeline) (A)	**26.5**	15.1	**73.4**	31.5
Other Operations	---	0.5	---	0.6
Consolidated operating income	**$ 187.3**	$ 185.8	**$ 291.6**	$ 264.9

(A) Excludes discontinued operations.

The following operating income analysis by business segment includes intercompany transactions that are eliminated in the condensed consolidated financial statements.

OG&E

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2003**	2002	**2003**	2002
Operating revenues	**$ 540.3**	$ 488.9	**$ 1,230.9**	$ 1,103.2
Fuel	**181.9**	140.4	**448.8**	338.2
Purchased power	**84.2**	66.9	**218.2**	196.0
Gross margin on revenues	**274.2**	281.6	**563.9**	569.0
Other operating expenses	**113.4**	111.4	**345.7**	336.2
Operating income	**$ 160.8**	$ 170.2	**$ 218.2**	$ 232.8
System sales - MWH (A)	**7.6**	7.5	**19.3**	19.1
Off-system sales - MWH	---	0.1	**0.1**	0.2
Total sales - MWH	**7.6**	7.6	**19.4**	19.3

(A) Megawatt-hour

Quarter ended September 30, 2003 compared to quarter ended September 30, 2002

OG&E's operating income for the three months ended September 30, 2003 decreased approximately $9.4 million or 5.5 percent as compared to the same period in 2002. The decrease in operating income was primarily attributable to lower electric rates due to the January 2003 rate reduction and lower recoveries of fuel costs from Arkansas customers partially offset by stronger weather-related demand and customer growth in OG&E's service territory.

The gross margin, which is operating revenues less cost of goods sold, was approximately $274.2 million for the three months ended September 30, 2003 as compared to approximately $281.6 million during the same period in 2002, a decrease of approximately $7.4 million or 2.6 percent. The gross margin decreased due to lower electric rates resulting from OG&E's rate reduction, which went into effect on January 6, 2003 (approximately $7.4 million), lower recoveries of fuel costs from Arkansas customers through that state's automatic fuel adjustment clause (approximately $5.6 million) and lower off-system sales (approximately $0.5 million). Partially offsetting the decrease in gross margin was an increase of approximately $4.1 million due to stronger weather-related demand in OG&E's service territory and an increase of approximately $2.1 million due to customer growth.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $181.9 million for the three months ended September 30, 2003 as compared to approximately $140.4 million during the same period in 2002, an increase of approximately $41.5 million or 29.6 percent. The increase was due primarily to an increase in the average cost of fuel per kilowatt-hour ("kwh") due to higher natural gas prices. Purchased power costs were approximately $84.2 million for the three months ended September 30, 2003 as compared to approximately $66.9 million during the same period in 2002, an increase of approximately $17.3 million or 25.9 percent. The increase was due to approximately a 51.6 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 OG&E's customers through automatic fuel adjustment clauses. While the regulatory mechanisms for recovering fuel costs differ in Oklahoma and Arkansas, the accounting method used to account for fuel costs is intended to provide neither an ultimate benefit nor detriment to OG&E's earnings. 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.

Other operating expenses, consisting of operating and maintenance expense, depreciation expense and taxes other than income, were approximately $113.4 million for the three months ended September 30, 2003 as compared to approximately $111.4 million during the same period in 2002, an increase of approximately $2.0 million or 1.8 percent. This increase was primarily due to an increase of approximately $3.3 million in pension and benefit expenses and an increase of approximately $1.9 million in miscellaneous other items. These increases were partially offset by a decrease of approximately $1.6 million in uncollectibles expense and a decrease of approximately $1.4 million in outside services.

Nine months ended September 30, 2003 compared to nine months ended September 30, 2002

OG&E's operating income for the nine months ended September 30, 2003 decreased approximately $14.6 million or 6.3 percent as compared to the same period in 2002. The decrease in operating income was primarily attributable to lower electric rates due to the January 2003 rate reduction and higher operating and maintenance expenses partially offset by stronger weather-related demand and customer growth in OG&E's service territory.

The gross margin was approximately $563.9 million for the nine months ended September 30, 2003 as compared to approximately $569.0 million during the same period in 2002, a decrease of approximately $5.1 million or 0.9 percent. Gross margin decreased for the nine months ended September 30, 2003 due to lower electric rates resulting from OG&E's rate reduction (approximately $17.5 million), a decrease of approximately $2.4 million due to the loss of revenue associated with various rate riders and lower off-system sales of approximately $1.3 million. Partially offsetting the decrease in gross margin was an increase of approximately $14.1 million due to customer growth, the loss of revenue in January 2002, associated with the interruption of service to our customers as a result of the severe January 2002 ice storm (approximately $1.5 million) and approximately a $0.8 million increase due to stronger weather-related demand in OG&E's service territory.

Fuel expense was approximately $448.8 million for the nine months ended September 30, 2003 as compared to approximately $338.2 million during the same period in 2002, an increase of approximately $110.6 million or 32.7 percent. The increase was due primarily to an increase in the average cost of fuel per kwh due to higher natural gas prices. Purchased power costs were approximately $218.2 million for the nine months ended September 30, 2003 as compared to approximately $196.0 million during the same period in 2002, an increase of approximately

$22.2 million or 11.3 percent. The increase was primarily due to approximately a 27.7 percent increase in the volume of energy purchased primarily due to economic purchases.

Other operating expenses, consisting of operating and maintenance expense, depreciation expense and taxes other than income, were approximately $345.7 million for the nine months ended September 30, 2003 as compared to approximately $336.2 million during the same period in 2002, an increase of approximately $9.5 million or 2.8 percent. The increase was primarily due to approximately a $9.2 million increase in operating and maintenance expenses. This increase was primarily due to approximately $5.4 million of 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. Also contributing to the increase in operating and maintenance expenses was an increase of approximately $1.7 million in outside services. Pension and benefit expenses increased approximately $6.8 million for the nine months ended September 30, 2003 as compared to the same period in 2002 due to the general upward trend in these costs. These increases were partially offset by lower levels of uncollectibles expense of approximately $4.5 million.

Enogex – Continuing Operations

	Three Months Ended September30,		**Nine Months Ended September 30,**	
(Dollars in millions)	**2003**	2002	**2003**	2002
Operating revenues	**$ 533.3**	$ 412.5	**$ 1,786.1**	$ 1,125.9
Gas and electricity purchased for resale	**460.0**	344.4	**1,556.3**	918.8
Natural gas purchases - other	**9.1**	13.9	**42.9**	55.4
Gross margin on revenues	**64.2**	54.2	**186.9**	151.7
Other operating expenses	**37.7**	39.1	**113.5**	120.2
Operating income	**$ 26.5**	$ 15.1	**$ 73.4**	$ 31.5
Physical system supply (A) - MMbtu/d (B)	**1,520**	1,767	**1,551**	1,688
Natural gas processed - MMcfd (C)	**412**	469	**416**	503
Natural gas liquids sold - million gallons	**58.3**	78.4	**178.4**	239.6
Average sales price per gallon	**$ 0.590**	$ 0.437	**$ 0.601**	$ 0.399
Natural gas marketed - Bbtu (D)	**87,299**	100,790	**277,071**	293,186
Average sales price per Bbtu	**$ 3.731**	$ 3.010	**$ 5.027**	$ 2.943

(A) Includes gathered volumes and incremental transported volumes.
(B) Million British thermal units per day.
(C) Million cubic feet per day.
(D) Billion British thermal units.

Quarter ended September 30, 2003 compared to quarter ended September 30, 2002

Enogex's operating income for the three months ended September 30, 2003 increased approximately $11.4 million or 75.5 percent as compared to the same period in 2002. The improvement in financial performance was primarily attributable to better operating performance resulting from higher gross margins in all of Enogex's businesses, increased levels of firm transportation revenues, improved processing results, the negotiation of both new contracts and replacements for expiring contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas and lower operating and maintenance expenses. Enogex sold its E&P business and its interest in Belvan during 2002 and Enogex sold its interest in NuStar during the first quarter of 2003; accordingly, these are reported as discontinued operations for the three months ended September 30, 2003 and 2002 in the condensed consolidated financial statements. See “Enogex — Discontinued Operations” below for a further discussion.

Transportation and storage contributed approximately $38.9 million of Enogex’s gross margin for the three months ended September 30, 2003 as compared to approximately $33.2 million during the same period in 2002, an increase of approximately $5.7 million or 17.2 percent. Gross margins benefited from increased storage revenues of approximately $3.2 million during the three months ended September 30, 2003 as compared to the same period in 2002. The increased storage revenues were mainly due to new demand fees related to the Stuart Facility acquired in the third quarter of 2002 and increased demand fees from both third parties and Enogex’s marketing and trading business. Also contributing to the increase were increased levels of firm transportation revenues of approximately $3.0 million as a result of the Calpine Energy settlement and an increase in related demand fees recognized in the third quarter of 2003.

These increases were partially offset by approximately a $2.2 million decrease due to an internal revenue allocation from Enogex's transportation and storage business to Enogex's gathering and processing business to more accurately reflect the performance of our businesses.

Gathering and processing contributed approximately $23.5 million of Enogex’s gross margin for the three months ended September 30, 2003 as compared to approximately $19.5 million during the same period in 2002, an increase of approximately $4.0 million or 20.5 percent. Processing gross margins increased approximately $0.7 million for the three months ended September 30, 2003 as compared to the same period in 2002. This increase was primarily due to wider commodity spreads between natural gas and natural gas liquids and better management and dispatch of the plants. Processing volumes were lower as a result of economically dispatching the plants based upon market conditions of the commodity spreads. Gathering gross margins increased approximately $3.3 million for the three months ended September 30, 2003 as compared to the same period in 2002. This increase was due to approximately a $2.2 million internal revenue allocation from Enogex's transportation and storage business to Enogex's gathering and processing business to more accurately reflect the performance of our businesses. Also contributing to the increase was approximately a $1.7 million increase due to the negotiation of both new contracts and replacements for expiring contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas. Gathered volumes were also up due to an increase in the number of well connects for the three months ended September 30, 2003 as compared to the same period in 2002.

Marketing and trading contributed approximately $1.8 million of Enogex’s gross margin for the three months ended September 30, 2003 as compared to approximately $1.5 million during the same period in 2002, an increase of approximately $0.3 million or 20.0 percent. The increase was primarily due to increased purchases and sales activity with our primary customers, partially offset by the change in the timing of revenue recognition related to natural gas in storage under SFAS No. 133 during the three months ended September 30, 2003 as compared to mark-to-market accounting during the three months ended September 30, 2002. This accounting change was driven by the rescission of mark-to-market accounting for natural gas in storage as a result of Emerging Issues Task Force ("EITF") Issue No. 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities" which was issued in October 2002. See "Accounting Pronouncements" for a further discussion.

Other operating expenses, consisting of operating and maintenance expense, depreciation expense and taxes other than income, for Enogex were approximately $37.7 million for the three months ended September 30, 2003 as compared to approximately $39.1 million during the same period in 2002, a decrease of approximately $1.4 million or 3.6 percent. Operating and maintenance expenses were approximately $22.1 million for the three months ended September 30, 2003 as compared to approximately $23.6 million during the same period in 2002, a decrease of approximately $1.5 million or 6.4 percent. The decrease was primarily due to lower benefit expenses of approximately $0.5 million due to over charges in the first six months of 2003, lower building and other rental expense of approximately $0.7 million, lower miscellaneous operating expenses of approximately $0.7 million, lower expense allocations from the parent of approximately $0.5 million due to lower expenses at the holding company and

lower materials and supplies expense of approximately $0.3 million. These decreases were partially offset by higher payroll expenses of approximately $1.0 million. Depreciation expense was approximately $11.0 million for the three months ended September 30, 2003 as compared to approximately $12.1 million during the same period in 2002, a decrease of approximately $1.1 million or 9.1 percent. The decrease was primarily the result of ceasing depreciation on the assets written down and classified as held for sale in the fourth quarter of 2002. Taxes other than income was approximately $4.6 million for the three months ended September 30, 2003 as compared to approximately $3.4 million during the same period in 2002, an increase of approximately $1.2 million or 35.3 percent. The increase was the result of higher ad valorem tax accruals.

Nine months ended September 30, 2003 compared to nine months ended September 30, 2002

Enogex’s operating income for the nine months ended September 30, 2003 increased approximately $41.9 million or 133.0 percent as compared to the same period in 2002. The increase was primarily attributable to better operating performance resulting from higher gross margins in all of Enogex’s businesses, improved management of pipeline system fuel, increased levels of firm transportation revenues, the negotiation of both new contracts and replacements of expiring contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas, the assistance of default processing fees and lower operating and maintenance expenses. Enogex sold its E&P business and its interest in Belvan during 2002 and Enogex sold its interest in NuStar during the first quarter of 2003; accordingly, these are reported as discontinued operations for the nine months ended September 30, 2003 and 2002 in the condensed consolidated financial statements. See “Enogex — Discontinued Operations” below for a further discussion.

Transportation and storage contributed approximately $101.9 million of Enogex’s gross margin for the nine months ended September 30, 2003 as compared to approximately $85.2 million during the same period in 2002, an increase of approximately $16.7 million or 19.6 percent. Gross margins benefited from increased storage revenues of approximately $9.2 million during the nine months ended September 30, 2003 as compared to the same period in 2002. The increased storage revenues were mainly due to new demand fees related to the Stuart Facility acquired in the third quarter of 2002 and increased demand fees from both third parties and Enogex’s marketing and trading business. Also contributing to the increase was improved management of pipeline system fuel which, when coupled with higher natural gas prices, accelerated the authorized recovery of pipeline system fuel expense of approximately $5.9 million. Also contributing to the increase were increased levels of firm transportation revenues of approximately $5.4 million as a result of the Calpine Energy settlement and an increase in related demand fees recognized in the third quarter of 2003. These increases were partially offset by approximately a $3.9 million decrease due to an internal revenue allocation from Enogex's transportation and storage business to Enogex's gathering and processing business to more accurately reflect the performance of our businesses.

Gathering and processing contributed approximately $67.0 million of Enogex’s gross margin for the nine months ended September 30, 2003 as compared to approximately $54.3 million during the same period in 2002, an increase of approximately $12.7 million or 23.4

percent. Processing gross margins increased approximately $6.3 million for the nine months ended September 30, 2003 as compared to the same period in 2002. This increase was primarily due to wider commodity spreads between natural gas and natural gas liquids, better management and dispatch of the plants and the assistance of default processing fees implemented in certain months under certain market conditions. Processing volumes were lower as a result of economically dispatching the plants based upon market conditions of the commodity spreads. Gathering gross margins increased approximately $6.4 million for the nine months ended September 30, 2003 as compared to the same period in 2002 primarily due to an internal revenue allocation from Enogex's transportation and storage business to Enogex's gathering and processing business to more accurately reflect the performance of our businesses and the negotiation of both new contracts and replacement for expiring contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas. Gathered volumes were also up due to an increase in the number of well connects for the nine months ended September 30, 2003 as compared to the same period in 2002.

Marketing and trading contributed approximately $18.0 million of Enogex’s gross margin for the nine months ended September 30, 2003 as compared to approximately $12.2 million during the same period in 2002, an increase of approximately $5.8 million or 47.5 percent. Gross margins included approximately $6.5 million from gains on the sale of natural gas in storage during the nine months ended September 30, 2003. These gains were largely offset by Enogex recording a $9.0 million pre-tax loss (not affecting gross margin), but as a cumulative effect of a change in accounting principle in the first quarter of 2003 as a result of accounting for certain energy contracts and natural gas in storage at the lower of cost or market rather than on a mark-to-market basis. See “Accounting Pronouncements” for a further discussion. Therefore, absent the impact of the change in accounting principle, gross margins would have been approximately $9.0 million during the nine months ended September 30, 2003 as compared to approximately $12.2 million during the same period in 2002. This $3.2 million decrease in the equivalent gross margin was due primarily to approximately a $1.8 million increase in demand fees paid to Enogex’s transportation and storage business and approximately a $0.8 million increase related to the change in the timing of revenue recognition related to natural gas in storage under SFAS No. 133 during the nine months ended September 30, 2003 as compared to mark-to-market accounting during the nine months ended September 30, 2002. This accounting change was driven by the rescission of mark-to-market accounting for natural gas in storage as a result of EITF 02-3 which was issued in October 2002. See "Accounting Pronouncements" for a further discussion.

Other operating expenses, consisting of operating and maintenance expense, depreciation expense and taxes other than income, for Enogex were approximately $113.5 million for the nine months ended September 30, 2003 as compared to approximately $120.2 million during the same period in 2002, a decrease of approximately $6.7 million or 5.6 percent. Operating and maintenance expenses were approximately $66.9 million for the nine months ended September 30, 2003 as compared to approximately $71.4 million during the same period in 2002, a decrease of approximately $4.5 million or 6.3 percent. The decrease was primarily due to lower expense allocations from the parent of approximately $1.5 million, lower materials and supplies expense of approximately $1.4 million, lower payroll expenses of approximately $0.9

million, lower uncollectibles expense of approximately $0.8 million and lower miscellaneous operating expenses of approximately $0.4 million. These decreases were partially offset by higher outside service costs of approximately $1.2 million. Depreciation expense was approximately $33.2 million for the nine months ended September 30, 2003 as compared to approximately $37.3 million during the same period in 2002, a decrease of approximately $4.1 million or 11.0 percent. The decrease was primarily the result of ceasing depreciation on the assets written down and classified as held for sale in the fourth quarter of 2002. Taxes other than income was approximately $13.4 million for the nine months ended September 30, 2003 as compared to approximately $11.5 million during the same period in 2002, an increase of approximately $1.9 million or 16.5 percent. The increase was the result of higher ad valorem tax accruals.

Enogex — Discontinued Operations

On March 25, 2002, Enogex entered into an Agreement of Sale and Purchase with West Texas Gas, Inc. to sell all of its interests in Belvan for approximately $9.8 million. The effective date of the sale was January 1, 2002 and the closing occurred on March 28, 2002. The Company recognized approximately a $1.6 million after tax gain related to the sale of these assets.

On August 5, 2002, Enogex entered into an Agreement of Sale and Purchase with Chesapeake Exploration Limited Partnership to sell all of its exploration and production assets located in Oklahoma, Texas, Arkansas and Mississippi for approximately $15.0 million. The effective date of the sale was July 1, 2002 and the closing occurred on September 19, 2002. The Company recognized approximately a $2.3 million after tax loss related to the sale of these assets.

On November 14, 2002, Enogex entered into an Agreement of Sale and Purchase with Quicksilver Resources, Inc. to sell all of its exploration and production assets located in Michigan for approximately $32.0 million. The effective date of the sale was July 1, 2002 and the closing occurred on December 2, 2002. The Company recognized approximately a $2.9 million after tax gain related to the sale of these assets.

During the third quarter of 2002, the Company decided to sell all of its interests in NuStar. On January 23, 2003, Enogex entered into an Agreement of Sale and Purchase with Benedum Gas Partners, L.P. to sell all of the interests of its subsidiary, Enogex Products Corporation, in the west Texas properties consisting of NuStar, which has operations consisting of the extraction and sale of natural gas liquids, for approximately $37.0 million. The effective date of the sale was January 1, 2003 and the closing occurred on February 18, 2003. The Company recognized approximately a $1.4 million after tax gain related to the sale of these assets in the first quarter of 2003. The final accounting for the NuStar sale was completed in the third quarter of 2003 which resulted in an additional charge of approximately $0.2 million after tax which was recorded in the third quarter of 2003.

As a result of these sale transactions, Enogex’s E&P business, its interest in NuStar and its interest in Belvan, all of which were part of the Natural Gas Pipeline segment, have been

reported as discontinued operations for the three and nine months ended September 30, 2003 and 2002 in the condensed consolidated financial statements. Results for these discontinued operations are summarized and discussed below.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions)	**2003**	2002	**2003**	2002
Operating revenues	$ **---**	$ 19.2	**$ 7.8**	$ 60.4
Gas purchased for resale	**---**	11.4	**5.9**	35.6

Natural gas purchases - other	---	1.5	**0.6**	4.9
Gross margin on revenues	---	6.3	**1.3**	19.9
Other operating expenses	---	3.8	**1.4**	13.8
Operating income (loss)	**$** ---	$ 2.5	**$ (0.1)**	$ 6.1

As all of these operations were sold prior to the beginning of the second quarter of 2003, there was no gross margin from discontinued operations for the three months ended September 30, 2003 compared to approximately $6.3 million for the three months ended September 30, 2002. Gross margin was approximately $1.3 million and $19.9 million for the nine months ended September 30, 2003 and 2002, respectively. As all of these operations were sold prior to the beginning of the second quarter of 2003, there were no operating expenses from discontinued operations for the three months ended September 30, 2003 compared to approximately $3.8 million for the three months ended September 30, 2002. Other operating expenses were approximately $1.4 million and $13.8 million for the nine months ended September 30, 2003 and 2002, respectively. The decreases in the gross margin and other operating expenses were primarily attributable to the sale of Enogex's E&P business and Belvan during 2002 and the sale of NuStar in February 2003.

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

Other income includes, among other things, contract work performed by OG&E, non-operating rental income, gain on the sale of assets, profit on the retirement of fixed assets, minority interest income and miscellaneous non-operating income. Other income was approximately $7.0 million for the nine months ended September 30, 2003 as compared to approximately $1.3 million during the same period in 2002, an increase of approximately $5.7 million. The increase was primarily due to a pre-tax gain of approximately $5.3 million related to the sale of approximately 29 miles of transmission lines of the Ozark pipeline in January 2003.

Other expense includes, among other things, expenses from loss on the sale of assets, loss on retirement of fixed assets, minority interest expense, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions. Other expense was approximately $2.8 million for the three months ended September 30, 2003 as compared to approximately $1.3 million during the same period in 2002, an increase of approximately $1.5 million. This increase was primarily due to a $0.7 million loss from the dissolution of a lease in the third quarter, $0.6 million increase in the liability associated with the deferred compensation plan, a $0.1 million loss related to the sale of the Company aircraft during

the third quarter and a $0.1 million loss related to the retirement of fixed assets during the third quarter of 2003.

Other expense was approximately $6.3 million for the nine months ended September 30, 2003 as compared to approximately $2.9 million during the same period in 2002, an increase of approximately $3.4 million. This increase was primarily due to an increase of approximately $1.1 million in minority interest expense related to the gain from the sale of approximately 29 miles of transmission lines of the Ozark pipeline in January 2003 that was attributable to the minority interest. Also contributing to the increase was approximately a $1.0 million increase in the liability associated with the deferred compensation plan and a $0.7 million loss from the dissolution of a lease in the third quarter.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $24.1 million for the three months ended September 30, 2003 as compared to approximately $27.5 million during the same period in 2002, a decrease of approximately $3.4 million or 12.4 percent. This decrease was primarily due to a reduction in interest expense of approximately $1.5 million related to the retirement of $140.0 million of Enogex debt during 2002, a $1.3 million decrease related to lower interest rates on outstanding debt achieved from entering into interest rate swap agreements and a $0.3 million decrease in variable rate debt interest.

Net interest expense was approximately $73.8 million for the nine months ended September 30, 2003 as compared to approximately $82.3 million during the same period in 2002, a decrease of approximately $8.5 million or 10.3 percent. This decrease was primarily due to a reduction in interest expense of approximately $6.2 million related to the retirement of $140.0 million of Enogex debt during 2002, a $1.5 million decrease in interest expense due to a lower average commercial paper balance in 2003 as compared to 2002 and a $1.4 million decrease related to lower interest rates on outstanding debt achieved from entering into interest rate swap agreements. These decreases were partially offset by a $0.7 million increase in bank fees.

Income tax expense was approximately $59.4 million for the three months ended September 30, 2003 as compared to approximately $60.7 million during the same period in 2002, a decrease of approximately $1.3 million or 2.1 percent. The decrease was primarily due to lower income taxes attributable to permanent differences for the three months ended September 30, 2003 as compared to the same period in 2002.

Income tax expense was approximately $80.7 million for the nine months ended September 30, 2003 as compared to approximately $67.2 million during the same period in 2002, an increase of approximately $13.5 million or 20.1 percent. The increase was primarily due to higher pre-tax income for Enogex partially offset by lower pre-tax income for OG&E. In addition, there was an increase in permanent differences for the nine months ended September 30, 2003 as compared to the same period in 2002.

Financial Condition

The balance of Accounts Receivable, Net was approximately $354.8 million and $304.6 million at September 30, 2003 and December 31, 2002, respectively, an increase of approximately $50.2 million or 16.5 percent. The increase was primarily due to an increase in OG&E's fuel costs for September 2003 as compared to December 2002, stronger weather-related demand and higher natural gas prices associated with Enogex's activities in the third quarter of 2003 partially offset by the rate reduction ordered for OG&E in November 2002 and lower volumes associated with Enogex's activities in the third quarter of 2003.

The balance of Accrued Unbilled Revenues was approximately $58.9 million and $28.2 million at September 30, 2003 and December 31, 2002, respectively, an increase of approximately $30.7 million or 108.9 percent. The increase was primarily due to higher fuel costs, higher seasonal electric rates and increased usage due to stronger weather-related demand during September 2003 as compared to December 2002.

The balance of Fuel Inventories was approximately $120.7 million and $99.7 million at September 30, 2003 and December 31, 2002, respectively, an increase of approximately $21.0 million or 21.1 percent. The increase was due to more volumes injected at higher prices during September 2003 as compared to December 2002.

The balance of current Price Risk Management assets was approximately $39.0 million and $17.1 million at September 30, 2003 and December 31, 2002, respectively, an increase of approximately $21.9 million or 128.1 percent. The increase was due to significant volatility and higher natural gas prices associated with OERI's trading activities during the first nine months of 2003. This increase is partially offset by an increase in current Price Risk Management liabilities.

The balance of Prepaid Benefit Obligation was approximately $65.5 million and $44.9 million at September 30, 2003 and December 31, 2002, respectively, an increase of approximately $20.6 million or 45.9 percent. The increase was due to the pension plan funding during the third quarter of 2003 partially offset by a decrease due to pension accruals being credited to the prepaid benefit obligation.

The balance of Short-Term Debt was approximately $96.8 million and $275.0 million at September 30, 2003 and December 31, 2002, respectively, a decrease of approximately $178.2 million or 64.8 percent. The decrease was primarily due to proceeds received from the sale of the Company's common stock in the third quarter of 2003, the sale of the Company aircraft in the third quarter of 2003, the sale of Ozark and NuStar and from the sale of natural gas inventory by Enogex during the first quarter of 2003, which were used to reduce the commercial paper balance at the holding company.

The balance of Accounts Payable was approximately $242.9 million and $269.0 million at September 30, 2003 and December 31, 2002, respectively, a decrease of approximately $26.1

million or 9.7 percent. This decrease was primarily due to lower volumes and higher natural gas prices associated with Enogex's activities in the third quarter of 2003.

The balance of current Price Risk Management liabilities was approximately $24.9 million and $13.9 million at September 30, 2003 and December 31, 2002, respectively, an increase of approximately $11.0 million or 79.1 percent. The increase was due to significant volatility and higher natural gas prices associated with OERI's trading activities during the first nine months of 2003. This increase was offset by an increase in current Price Risk Management assets.

Liquidity and Capital Requirements

General

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, operating lease obligations, hedging activities, natural gas storage and delays in recovering unconditional purchase obligations. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings and permanent financings.

Equity Issuance

On August 27, 2003 and September 5, 2003, respectively, the Company issued 4,650,000 shares and 674,074 shares of its common stock at $21.60 per share. The Company plans to use the proceeds received from this offering to make a capital contribution to OG&E, which will, in turn, use such funds to pay a portion of the purchase price of its pending acquisition of the McClain Plant. Pending completion of the acquisition, the proceeds will be used for general corporate purposes, including repayment of commercial paper.

Income Taxes

In connection with the filing in the third quarter of 2003 of the Company's consolidated income tax returns for 2002, the Company elected to change its tax method of accounting related to the capitalization of costs for self-constructed assets to another method prescribed in the Treasury regulations. The accounting method change is for income tax purposes only. For financial accounting purposes, the only change 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 the Company's current federal and state income tax liability for 2002 and all estimated payments made for 2002 have been or will be refunded. As a result of this tax net operating loss, tax credits associated with Enogex's natural gas production

were not realized and resulted in approximately $1.8 million in higher income tax expense in discontinued operations.

Interest Rate Swap Agreements

At September 30, 2003 and December 31, 2002, the Company had three outstanding interest rate swap agreements: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate ("LIBOR") and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert $100.0 million each of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR.

These interest rate swaps qualified as fair value hedges under Statement of Financial Accounting Standards ("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. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards.

At September 30, 2003 and December 31, 2002, the fair values pursuant to the interest rate swaps were approximately $14.2 million and $15.9 million, respectively, and were included in non-current Price Risk Management assets in the accompanying Condensed Consolidated Balance Sheets. A corresponding net increase of approximately $14.2 million and $15.9 million was reflected in Long-Term Debt at September 30, 2003 and December 31, 2002, respectively, as these fair value hedges were effective at September 30, 2003 and December 31, 2002.

Future Capital Requirements

The Company's current 2003 to 2005 construction program includes the purchase of an additional power plant as discussed below; however, the Company will continue to review all of the supply alternatives to replace expiring QF contracts that minimize the total cost of generation to our customers. Unless extended by OG&E, 540 MWs of QF contracts will expire over the next one to five years. Accordingly, OG&E will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in projected natural gas prices, OG&E will include the feasibility of constructing additional base load coal-fired units in its build options.

On August 18, 2003, OG&E 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 plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. Closing is subject to numerous conditions. See "Overview – Pending Acquisition of Power Plant." If approval is received, funding for the acquisition is to be provided by proceeds received by the Company from its equity offering in the third quarter of 2003, and a debt issuance by OG&E. To reliably meet the increased electricity needs of OG&E's

customers during the foreseeable future, OG&E will continue to invest to maintain the integrity of the delivery system. Approximately $4.9 million of the Company's capital expenditures budgeted for 2003 are to comply with environmental laws and regulations.

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

General

Apart from the funds required to purchase the McClain Plant discussed above, management expects that internally generated funds 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. The Company issued equity in the third quarter of 2003 and OG&E plans to issue debt in the fourth quarter of 2003 to fund the purchase of the electric generating plant.

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. The following table shows the Company's lines of credit in place at October 31, 2003. Short-term borrowings will consist of a combination of bank borrowings and commercial paper.

Lines of Credit *(In millions)*

Entity	Amount	Maturity
OGE Energy Corp. (A)	$ 200.0	January 8, 2004
	100.0	January 15, 2004
	15.0	April 6, 2004
OG&E	100.0	June 26, 2004
Total	$ 415.0	

(A) The lines of credit at OGE Energy Corp. are used to back up the Company's commercial paper borrowings. There were no commercial paper borrowings outstanding at October 31, 2003. No borrowings were outstanding at October 31, 2003 under any of the lines of credit shown above; however, $8.0 million of the $15.0 million line of credit above is supported by a letter of credit described in "Commitments and Contingencies – Guarantees."

The Company's ability to access the commercial paper market could be adversely impacted by a commercial paper ratings downgrade. The lines of credit contain ratings triggers that require annual fees and borrowing rates to increase if the Company suffers an adverse ratings impact. The impact of additional downgrades of the Company'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 ratings triggers. See "Security

Ratings" for potential financing needs upon a downgrade by Moody's Investors Service ("Moody's") of Enogex's long-term debt rating.

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

Security Ratings

On January 15, 2003, Standard & Poor's Ratings Services ("Standard &Poor's") lowered the credit ratings of OGE Energy Corp.'s senior unsecured debt from A- to BBB. Standard & Poor's also lowered the credit ratings of OG&E's and Enogex's senior unsecured debt from A- to BBB+. OGE Energy Corp.'s short-term commercial paper ratings were affirmed at A-2. The outlook is now stable. Standard & Poor's cited the relatively low-risk low-cost efficient operations of OG&E and the business and financial profile of Enogex, which has higher risk. Standard & Poor's further cited the rationalization at Enogex has resulted in a business-risk reduction, but it is not adequate to warrant an improvement in the overall business score. 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 consolidated financial position or results of operations.

On February 5, 2003, Moody's lowered the credit ratings of OGE Energy Corp.'s senior unsecured debt to Baa1 from A3, OG&E's senior unsecured debt to A2 from A1 and Enogex's senior unsecured debt to Baa3 from Baa2. OGE Energy Corp.'s short-term commercial paper rating was unchanged at P-2. The outlook for OGE Energy Corp. and OG&E is stable and Enogex is negative. Moody's cited the diminished credit profile of both OG&E and Enogex with OG&E having competitive generation and stable cash flow but with regulatory risk associated with the acquisition of at least 400 MWs of new generation and Enogex exposed to the seasonality of its gas processing business although it has reduced its keep-whole exposure. 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 consolidated financial position or results of operations. As a result of Enogex's rating being lowered to Baa3, OGE Energy Corp. was required to issue a $5.0 million guarantee on Enogex's behalf for a counterparty. At September 30, 2003, there is no outstanding liability balance related to this guarantee. In the event one or more of the credit ratings were to fall below investment grade, Enogex may seek OGE Energy Corp. guarantees to satisfy its customers in order to avoid disruption of its marketing and trading business.

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.

Asset Sales

Also contributing to the liquidity of the Company have been numerous asset sales by Enogex. Since January 1, 2002, completed sales generated net proceeds of approximately $101.3 million. Sales proceeds generated to date have been used to reduce debt at Enogex and commercial paper at the holding company.

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

Critical Accounting Policies and Estimates

The Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements included in this Form 10-Q and in the Company's Form 10-K for the year ended December 31, 2002 contain information that is pertinent to Management's Discussion and Analysis. In preparing the 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. Changes to these assumptions and estimates could have a material effect on the Company's condensed 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 are in the valuation of pension plan assumptions, impairment estimates, contingency reserves, unbilled revenue for OG&E, the allowance for uncollectible accounts receivable and the valuation of energy purchase and sale contracts and natural gas storage inventory. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's audit committee.

Consolidated (including Electric Utility and Natural Gas Pipeline Segments)

Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets 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 13 of the Notes to Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2002.

The Company assesses potential impairments of assets when there is evidence that events or changes in circumstances indicate that an asset's carrying value may not be recoverable. An impairment loss is recognized when the sum of the expected future net cash flows is less than the

carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset.

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 condensed consolidated financial statements.

Electric Utility Segment

OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Condensed Consolidated Balance Sheets and in Operating Revenues on the Condensed Consolidated Statements of Income based on estimates of usage and prices during the period. At September 30, 2003 and December 31, 2002, Accrued Unbilled Revenues were approximately $58.9 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.

All customer balances are written off if not collected within six months after the account is finalized. 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 is a reduction to Accounts Receivable on the Condensed Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Condensed Consolidated Statements of Income. The allowance for uncollectible accounts receivable for OG&E was approximately $2.6 million and $4.7 million at September 30, 2003 and December 31, 2002, respectively.

Natural Gas Pipeline Segment

Operating revenues for transportation, storage, gathering and processing services for Enogex are estimated each month based on the prior month's activity, historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current month nominations and contracted prices. Operating revenues associated with the production of natural gas liquids are estimated based on current month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated operating revenues are reflected in Accounts

Receivable on the Condensed Consolidated Balance Sheets and in Operating Revenues on the Condensed Consolidated Statements of Income.

Estimates for gas purchases are based on sales volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable on the Condensed Consolidated Balance Sheets and in Cost of Goods Sold on the Condensed Consolidated Statements of Income.

In October 2002, the EITF reached a consensus to rescind EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," as amended effective for fiscal periods beginning after December 15, 2002. Effective October 25, 2002, all new contracts and physical inventories that would have been accounted for under EITF 98-10 were no longer marked to market through earnings unless the contracts met the definition of a derivative under SFAS No. 133. Contracts and physical inventories that existed at October 25, 2002 continued to be accounted for under EITF 98-10 through December 31, 2002. Effective January 1, 2003, these contracts were revalued in accordance with provisions of EITF 02-3 which rescinded EITF 98-10. The change in the value of these contracts is shown as a cumulative effect of a change in accounting principle in the accompanying Condensed Consolidated Statements of Income. Energy contracts are entered into by OGE Energy Resources, Inc. ("OERI"), the marketing subsidiary of Enogex. Corporate risk management and credit committees charged with enforcing the trading and credit policies, which include specific guidance on counterparties, procedures, credit and trading limits, monitor these activities. Marketing activities include the trading and marketing of natural gas, electricity and natural gas liquids. 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 the mark-to-market valuation, and an oversight group outside of the marketing organization monitors all modeling methodologies and assumptions. The recorded value of the energy contracts may change significantly in the future as the market price for the commodity changes, but the value is still subject to the risk loss limitations provided under the Company's risk policies. The Company utilizes a model to estimate the fair value of its energy contracts including derivatives that do not have an independent market price. At September 30, 2003, unrealized mark-to-market gains were approximately $7.1 million, which included approximately $0.2 million of unrealized mark-to-market losses that were calculated utilizing models. Energy contracts are presented in Price Risk Management assets and liabilities on the Condensed Consolidated Balance Sheets and in Operating Revenues on the Condensed Consolidated Statements of Income. See "Accounting Pronouncements" for a further discussion.

Effective January 1, 2003, natural gas storage inventory used in OERI's business activities are accounted for at the lower of cost or market in accordance with the guidance in EITF 02-3, which resulted in the rescission of EITF 98-10. Prior to January 1, 2003, this inventory was accounted for on a fair value accounting basis utilizing a gas index that in management's opinion approximated the current market value of natural gas in that region as of the Balance Sheet date. On April 1, 2003, natural gas storage inventory used in OERI's business activities began to be accounted for under SFAS No. 133. In order to minimize risk, OERI enters into contracts or hedging instruments to hedge the fair value of this inventory. For any contracts

that qualify for hedge accounting under SFAS No. 133, the hedged portion of the inventory is recorded at fair value with an offsetting gain or loss recorded currently in earnings. The fair value of the hedging instrument is also recorded on the books of the Company as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. At September 30, 2003, the Company had all natural gas inventory hedged with qualified fair value hedges under SFAS No. 133. As part of its recurring business activity, OERI injects and withdraws natural gas under the terms of storage capacity contracts; the amount of natural gas inventory was approximately $56.8 million and $32.9 million at September 30, 2003 and December 31, 2002, respectively. See "Accounting Pronouncements" for a further discussion. Natural gas storage inventory is presented in Fuel Inventories on the Condensed Consolidated Balance Sheets and in Cost of Goods Sold on the Condensed Consolidated Statements of Income.

The allowance for uncollectible accounts receivable is established on a case-by-case basis when the Company believes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Condensed Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Condensed Consolidated Statements of Income. The allowance for uncollectible accounts receivable for the Natural Gas Pipeline segment was approximately $2.0 million and $8.9 million at September 30, 2003 and December 31, 2002, respectively.

Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 affects the Company's accrued plant removal costs for generation, transmission, distribution and processing facilities 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. 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 is 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 consolidated 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. As described below, amounts recovered from ratepayers related to estimated asset retirement obligations recorded as a liability in Accumulated Depreciation were reclassified as a regulatory liability in the first quarter of 2003.

SFAS No. 143 also requires that, if the conditions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" 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 adoption of SFAS No. 143, the Company was required to quantify the amount of asset retirement costs previously recovered from ratepayers 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 Condensed Consolidated Balance Sheet. At September 30, 2003, the regulatory liability for accrued removal obligations, net was approximately $113.9 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 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 is 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 consolidated financial position or results of operations.

In October 2002, the EITF reached a consensus on certain issues covered in EITF 02-3. One consensus of EITF 02-3 requires that all mark-to-market gains and losses, whether realized or unrealized, on financial derivative contracts as defined in SFAS No. 133 be shown net in the Income Statement for financial statements issued for periods beginning after December 15, 2002, with reclassification required for prior periods presented. The Company adopted this consensus effective January 1, 2003 and the application of this consensus did not have a material impact on its consolidated financial position or results of operations as this consensus supports the Company's historical presentation of financial derivative contracts.

In October 2002, the EITF reached a consensus to rescind EITF 98-10 effective for fiscal periods beginning after December 15, 2002. Effective October 25, 2002, all new contracts and physical inventories that would have been accounted for under EITF 98-10 were no longer marked to market through earnings unless the contracts met the definition of a derivative under SFAS No. 133. Application of the consensus for energy contracts and inventory that existed on

or before October 25, 2002 that remained in effect at the date this consensus was initially applied were recognized as a cumulative effect of a change in accounting principle in accordance with Accounting Principles Board ("APB") Opinion No. 20, "Accounting Changes." As a result, only energy contracts that meet the definition of a derivative in SFAS No. 133 are carried at fair value. The Company adopted this consensus effective January 1, 2003 resulting in an approximate $9.6 million pre-tax loss ($5.9 million after tax). The loss, which was accounted for as a cumulative effect of a change in accounting principle during the first quarter, was primarily related to natural gas held in storage for trading purposes. This natural gas held in storage was sold during the first quarter of 2003 resulting in an increase in the gross margin on revenues in excess of the cumulative effect loss described above.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure — an amendment of FASB Statement No. 123." SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation which includes the prospective method, modified prospective method and retroactive restatement method. SFAS No. 148 also amends the disclosure requirements of SFAS No. 123, "Accounting for Stock-Based Compensation," to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. Adoption of the annual disclosure and voluntary transition requirements of SFAS No. 148 is required for annual financial statements issued for fiscal years ending after December 15, 2002. Adoption of the interim disclosure requirements of SFAS No. 148 is required for interim periods beginning after December 15, 2002. Pursuant to the provisions of SFAS No. 123, the Company has elected to continue using the intrinsic value method of accounting for its stock-based employee compensation plans in accordance with APB Opinion No. 25, "Accounting for Stock Issued to Employees." However, the Company has included the required disclosures under SFAS No. 148 in Note 1 of Notes to Condensed Consolidated Financial Statements.

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 consolidated 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 moves 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 will adopt this new interpretation effective December 31, 2003 and the adoption of this new interpretation is not expected to have a material impact on its consolidated 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 consolidated financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity." SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. The requirements of this statement apply to an issuer's classification and measurement of freestanding financial instruments, including those that comprise more than one option or forward contract. This statement does not apply to features that are embedded in a financial instrument that are not a derivative in its entirety. This statement also addresses questions about the classification of certain financial instruments that embody obligations to issue equity shares. SFAS No. 150 requires that instruments that are redeemable upon liquidation or termination of an issuing subsidiary that has a limited life are considered mandatorily redeemable shares under SFAS No. 150 in the consolidated financial

statements of the parent. Accordingly, these noncontrolling interests are required to be classified as liabilities under SFAS No. 150. All provisions of this statement, except the provisions related to a limited-life subsidiary, are effective for financial instruments entered into or modified after May 31, 2003, and otherwise are effective at the beginning of the first interim period beginning after June 15, 2003. Companies are not required to recognize noncontrolling interests of a limited-life subsidiary as a liability in the consolidated financial statements and should continue to account for these interests as minority interests until the FASB considers resulting implementation issues associated with the measurement and recognition guidance for these noncontrolling interests. Except for the provisions related to a limited-life subsidiary, 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 consolidated financial position or results of operations. The Company does not expect that the provisions related to a limited-life subsidiary will have a material impact on its consolidated financial position or results of operations.

Electric Competition; Regulation

Proposed Standard Market Design Rulemaking

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 and Omaha.

Reference is made to Note 13 and Note 14 of Notes to Condensed Consolidated Financial Statements in this report and to "Electric Competition; Regulation" in Item 7 of the Company's Form 10-K for the year ended December 31, 2002 for a discussion of pending regulatory actions involving OG&E or Enogex and of other initiatives to increase competition in the retail and wholesale sale of electricity.

Pending Acquisition of Power Plant

As part of its most recent rate settlement with the OCC, OG&E undertook to acquire electric generating capacity of not less than 400 MWs. The acquisition of a 77 percent interest in the McClain Plant discussed above would constitute an acquisition of such generation under the recent OCC settlement order. OG&E expects this new generation 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 OG&E because OG&E's rates would not need to be reduced to accomplish these savings. PowerSmith has filed an application with the OCC seeking to compel OG&E to continue purchasing power from PowerSmith's qualified cogeneration facility under the Public Utility Regulatory Policies Act of 1978 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 OG&E and PowerSmith or (ii) the avoided cost of the McClain Plant. OG&E 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. To the extent PowerSmith ultimately were successful, it would reduce OG&E's ability to realize the targeted $75 million of savings to its Oklahoma customers over a three-year period.

The decision of OG&E with respect to the purchase of this new generation will be subject to a review by the OCC as a part of its general rate case filed October 31, 2003 for the purpose of determining the level of just and reasonable costs associated with the new generation to be included in customers' rates. The OCC's review is expected to include, but not be limited to, an analysis and review of the alternatives to purchasing the new generation, the amount paid for such new generation and the level of capacity purchases. OG&E will provide monthly reports, for a period of 36 months after the acquisition, to the OCC Staff, documenting and providing proof of savings experienced by OG&E's customers. In the event OG&E is unable to demonstrate at least $75.0 million in savings to its customers during this 36-month period, OG&E 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.

In the event OG&E does not acquire the new generation by December 31, 2003, the settlement order requires OG&E 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 OG&E 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.

Commitments and Contingencies

Except as set forth below, the circumstances set forth in Note 15 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2002 and in the Notes to the Company's Condensed Consolidated Financial Statements included in its Form 10-Q for the quarters ended March 31, 2003 and June 30, 2003, appropriately represent, in all material respects, the current status of any material commitments and contingent liabilities.

Agreement with Colorado Interstate Gas Company

In December 2002, Enogex entered into a Precedent Agreement with Colorado Interstate Gas Company ("CIG") regarding reservation of capacity on a proposed interstate gas pipeline (the "Cheyenne Plains Pipeline"). If completed, the Cheyenne Plains Pipeline would provide interstate gas transportation services in the states of Wyoming, Colorado and Kansas with a capacity of 560,000 decatherms/day ("Dth/day"). Under the Precedent Agreement, Enogex bid to reserve 60,000 Dth/day of capacity on the proposed pipeline for 10 years and two months. Such reservation would result in Enogex having access to significant additional natural gas supplies in the areas to be served by the proposed pipeline. Subject to regulatory and other approvals, CIG is proposing an in-service date of August 31, 2005.

On May 20, 2003, Cheyenne Plains filed its initial certificate applications with the FERC, including its proposed tariff for the pipeline, as well as certain environmental filings. On July 7, 2003, Enogex filed a motion to intervene, stating certain objections involving Cheyenne Plains' proposed treatment of reservation fees and creditworthiness requirements. Enogex participated in a FERC technical conference with Cheyenne Plains and other interveners in August 2003. The parties reached agreement on the issues raised regarding the proposed tariff provisions.

Guarantees

During the normal course of business, Enogex issues guarantees on behalf of its subsidiaries for the purpose of securing credit for certain business activities. These guarantees are for payment when due of amounts payable by its subsidiaries under various agreements with counterparties. At September 30, 2003, accounts payable supported by guarantees was approximately $47.9 million. Since these guarantees by Enogex represent security for payment of payables obtained in the normal course of its subsidiaries' business activities, the Company, on a consolidated basis, does not assume any additional liability as a result of this arrangement.

OGE Energy Corp. has issued a $5.0 million guarantee on behalf of OERI and a $15.0 million guarantee on behalf of Enogex Inc. for the purpose of securing credit for certain business activities. These guarantees are for payment when due of amounts payable by OERI and Enogex Inc. under various agreements with counterparties. At September 30, 2003, there are no accounts payable supported by these guarantees. Since these guarantees by OGE Energy Corp. represent security for payment of payables obtained in OERI's and Enogex Inc.'s business activities, the

Company, on a consolidated basis, does not assume any additional liability as a result of this arrangement.

The Company has issued an $8.0 million standby letter of credit to an insurance company, Energy Insurance Bermuda Ltd. Mutual Business Program No. 19 ("MBP 19"), for the benefit of insuring parts of the Company's property and liability insurance programs. MBP 19 was established to provide $15 million worth of property and liability insurance for the Company. The $8.0 million letter of credit was issued to provide protection for MBP 19 in case of large insurance claim losses. At September 30, 2003, there were no drawings against this letter of credit. This letter of credit renews automatically on an annual basis.

At September 30, 2003, in the event Moody's or Standard & Poor's were to lower Enogex's senior unsecured debt rating to a below investment grade rating, Enogex would be required to post approximately $6.4 million of collateral to satisfy its obligation under its financial and physical contracts.

Firm Transportation Contract with Calpine Energy Services, L.P.

In 2000, Enogex entered into long-term firm transportation contracts with an independent power producer relating to a plant to be built in Wagoner County, Oklahoma. Effective July 1, 2000, the contracts were assigned to Calpine Energy Services, L.P. ("Calpine Energy"). In February 2002, Enogex requested a prepayment from Calpine Energy due to Calpine falling below the contractual creditworthiness criteria set forth in the transportation contracts. Calpine Energy refused to pay, for the months of March 2002 through June 2002, the monthly demand fees pursuant to the transportation contracts on grounds of an alleged force majeure event and also refused to make any prepayments as requested. Enogex also made a demand on Calpine Corporation, as guarantor, relating to Calpine Energy's failure to make the required prepayment and demand payments. The parties entered into a letter agreement dated June 2002, whereby Calpine Energy paid 50 percent of the demand fees for the period beginning July 1, 2002 and continuing through October 31, 2002 and prepaid, on a monthly basis, 50 percent of the monthly demand payment. For the periods after October 31, 2002, Calpine Energy paid the entire monthly demand fee. In Enogex's judgment, the amount of demand revenues owing at September 30, 2003, was approximately $3.4 million, which amount had not been recognized in revenues or earnings on the Company's financial statements.

In September 2002, Calpine Energy and Calpine Corporation filed a declaratory judgment action in the United States District Court for the Northern District of Oklahoma. Calpine Energy sought a declaratory judgment that its failure to obtain permits was a force majeure event under the contract and therefore demand charges were not due and owing; and, that Enogex had no reasonable ground to question its creditworthiness under the contracts. Enogex answered and filed a counterclaim in October 2002. Enogex denied that the declaratory judgment requested was proper and sought, under the counterclaim, an award based on breach of the contracts and the guarantee.

After participating in a court ordered mediation on August 18, 2003, the parties reached a settlement of the pending issues on September 29, 2003. The terms of the settlement obligated Calpine Energy to make a nonrefundable payment to Enogex in the amount of $3.0 million and to maintain a prepayment. Enogex agreed to apply a credit of $1.0 million to the final two months' demand charges under the transportation contract. On September 30, 2003, the parties filed a Joint Stipulation of Dismissal with the trial court. On October 14, 2003, Enogex received payment of the settlement amount from Calpine Energy. As a result of this settlement, the Company recorded $2.0 million of the settlement payment as revenue in the third quarter.

Pending Acquisition of Power Plant

On August 18, 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the McClain Plant. The acquisition of this interest in the McClain Plant would constitute an acquisition of new generation under the recent OCC settlement order. The purchase price for the interest in the plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. See "Overview – Pending Acquisition of Power Plant" for a further discussion.

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 condensed consolidated financial statements. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. This assessment of currently pending or threatened lawsuits is subject to change.

Besides the various existing contingencies herein described, the Company's ability to fund its future operational needs and to finance its construction program could be impacted by 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.

Item 3. 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 certain commodity prices and interest rates. The Company engages in price risk management activities for both trading and non-trading purposes.

To manage the volatility relating to these exposures, the Company enters into various derivative 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's exposure to interest rate risk for changes in interest rates has not significantly changed since December 31, 2002. See Notes 10 and 11 of Notes to Condensed Consolidated Financial Statements.

Commodity Price Risk

The market risks inherent in the Company's market risk sensitive instruments, positions and anticipated commodity transactions are the potential losses in value arising from adverse changes in the Company's commodity prices.

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

The prices of natural gas, natural gas liquids and natural gas liquids processing spreads are subject to fluctuations resulting from changes in supply and demand. Processing spreads are the difference between the values of natural gas liquids compared to the value of an equivalent

amount of MMbtu in natural gas form. To partially reduce commodity price risk incurred in the Company's normal course of business 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 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, commodity purchase and sales contracts, financial and commodity derivative instruments and anticipated natural gas processing spreads and fuel recoveries. The fair value of such position is a summation of the fair values calculated for each commodity by valuing each net position at quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in such prices over the next 12 months. The results of this analysis, which may differ from actual results, are as follows as of September 30, 2003:

(In millions)	Trading	Non-Trading
Commodity market risk, net	$ 0.2	$ 3.1

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Item 4. 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.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Reference is made to Part I, Item 3 of the Company's Form 10-K for the year ended December 31, 2002 and to Part II, Item 1 of the Company's Form 10-Q for the quarters ended March 31, 2003 and June 30, 2003 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.

Natural Gas Measurement Cases

Will Price (Price I). On September 24, 1999, the Company was served with a class action petition filed in the District Court of Stevens County, Kansas by Quinque Operating Company and other named plaintiffs, alleging mismeasurement of natural gas on non-federal lands (Price I). The court entered an order denying class certification on April 10, 2003.

Plaintiffs filed a motion requesting permission to file an amended petition on May 12, 2003, and the court granted such motion on July 28, 2003. In this amended petition, Enogex Inc. and OG&E were omitted from the case with two subsidiaries of Enogex remaining as defendants. The Plaintiffs' 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.

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

Will Price (Price II). On May 12, 2003, the Plaintiffs (same as those in Price I above) filed a new class action petition (Price II) in the District Court of Stevens County, Kansas, relating to wrongful Btu analysis against natural gas pipeline owners and operators, naming the same defendants as in the amended petition of the Price I case. Enogex subsidiaries were served on August 4, 2003. The Plaintiffs seek to represent a class of only royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The class action petition alleges improper analysis of gas heating content. In all other respects, the Price II petition appears to be the same as the amended petition in Price I.

The defendants filed a motion to dismiss on August 25, 2003 and the court issued its order denying the motion to dismiss on October 9, 2003. Answers were filed by November 10, 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

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

Firm Transportation Contract with Calpine Energy Services, L.P.

After participating in a court ordered mediation on August 18, 2003, the parties reached a settlement of the pending issues on September 29, 2003. The terms of the settlement obligated Calpine Energy to make a nonrefundable payment to Enogex in the amount of $3.0 million and to maintain a prepayment. Enogex agreed to apply a credit of $1.0 million to the final two months' demand charges under the transportation contract. On September 30, 2003, the parties filed a Joint Stipulation of Dismissal with the trial court. On October 14, 2003, Enogex received payment of the settlement amount from Calpine Energy. As a result of this settlement, the Company recorded $2.0 million of the settlement payment as revenue in the third quarter.

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Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

Exhibit No.	Description

2.01	Asset Purchase Agreement, dated as of August 18, 2003 by and between OG&E and NRG McClain LLC (filed as Exhibit 2.01 to the Company's Form 8-K (file no. 1-12579) filed on August 20, 2003 and incorporated herein br reference).
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.

(b) Reports on Form 8-K

The Company filed a Current Report on Form 8-K on July 2, 2003 to report its decision to move OG&E’s request for a general rate change to later in 2003.

The Company filed a Current Report on Form 8-K on August 6, 2003 to report its consolidated results of operations and financial condition for the second quarter of 2003.

The Company filed a Current Report on Form 8-K on August 20, 2003 to report that it signed an asset purchase agreement to acquire a 77 percent interest in the NRG McClain Station.

The Company filed a Current Report on Form 8-K on August 25, 2003 to report that it entered into a Purchase Agreement relating to 4,650,000 shares of the Company’s Common Stock, par value $0.01 per share, plus an option to purchase an additional 674,074 shares.

The Company filed a Current Report on Form 8-K on September 16, 2003 to report that it filed with the Oklahoma Corporation Commission (“OCC”) a notice of intent to seek an annual increase in its rates to its Oklahoma customers of more than one percent.

The Company filed a Current Report on Form 8-K on October 31, 2003 to report that OG&E 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 consolidated results of operations and financial condition for the third quarter of 2003.

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)

November 12, 2003

Exhibit 31.01

CERTIFICATIONS

I, Steven E. Moore, certify that:

1. I have reviewed this quarterly report on Form 10-Q of OGE Energy Corp.;

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 officers 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 officers 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: November 12, 2003

/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 quarterly report on Form 10-Q of OGE Energy Corp.;

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 officers 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 officers 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: November 12, 2003

/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 Quarterly Report of OGE Energy Corp. (the "Company") on Form 10-Q for the period ended September 30, 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.

November 12, 2003

/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