NATIONAL FUEL GAS CO
Form 10-Q
February 08, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended December 31, 2012

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 1-3880

NATIONAL FUEL GAS COMPANY

(Exact name of registrant as specified in its charter)

(716) 857-7000

(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 and (2) has been subject to such filing requirements for the past 90 days. YES þ NO ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES þ NO ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer	þ	Accelerated Filer	¨
Non-Accelerated Filer	¨(Do not check if a smaller reporting company)	Smaller Reporting Company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ¨ NO þ

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Common stock, par value $1.00 per share, outstanding at January 31, 2013: 83,490,445 shares.

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GLOSSARY OF TERMS

Frequently used abbreviations, acronyms, or terms used in this report:

National Fuel Gas Companies

Company	The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure
Distribution Corporation	National Fuel Gas Distribution Corporation
Empire	Empire Pipeline, Inc.
ESNE	Energy Systems North East, LLC
Horizon Power	Horizon Power, Inc.
Midstream Corporation	National Fuel Gas Midstream Corporation
National Fuel	National Fuel Gas Company
NFR	National Fuel Resources, Inc.
Registrant	National Fuel Gas Company
Seneca	Seneca Resources Corporation
Supply Corporation	National Fuel Gas Supply Corporation

Regulatory Agencies

CFTC	Commodity Futures Trading Commission
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
NYDEC	New York State Department of Environmental Conservation
NYPSC	State of New York Public Service Commission
PaDEP	Pennsylvania Department of Environmental Protection
PaPUC	Pennsylvania Public Utility Commission
SEC	Securities and Exchange Commission

Other

2012 Form 10-K	The Company's Annual Report on Form 10-K for the year ended September 30, 2012
Bbl	Barrel (of oil)

Bcf	Billion cubic feet (of natural gas)
Bcfe (or Mcfe) – represents Bcf (or Mcf) Equivalent	The total heat value (Btu) of natural gas and oil expressed as a volume o natural gas. The Company uses a conversion formula of 1 barrel of oil = 6 Mcf of natural gas.
Btu	British thermal unit; the amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit
Capital expenditure	Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.
Cashout revenues	A cash resolution of a gas imbalance whereby a customer pays Supply Corporation and/or Empire for gas the customer receives in excess of amounts delivered into Supply Corporation's and Empire's systems by the customer's shipper.
Degree day	A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.
Derivative	A financial instrument or other contract, the terms of which include a underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net and no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, options, no cost collars and swaps.

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Development costs	Costs incurred to obtain access to proved oil and gas reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act.
Dth	Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.
Exchange Act	Securities Exchange Act of 1934, as amended
Expenditures for long-lived assets	Includes capital expenditures, stock acquisitions and/or investments in partnerships.
Exploration costs	Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.
Firm transportation and/or storage	The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.
GAAP	Accounting principles generally accepted in the United States of America
Goodwill	An intangible asset representing the difference between the fair value of a company and the price at which a company is purchased.
Hedging	A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes, often times through the use of derivative financial instruments.
Hub	Location where pipelines intersect enabling the trading, transportation, storage, exchange, lending and borrowing of natural gas.
Interruptible transportation and/or storage	The transportation and/or storage service that, in accordance with contractual arrangements, can be interrupted by the supplier of such service, and for which the customer does not pay unless utilized.
LIBOR	London Interbank Offered Rate
LIFO	Last-in, first-out
Marcellus Shale	A Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York.
Mbbl	Thousand barrels (of oil)
Mcf	Thousand cubic feet (of natural gas)
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MDth	Thousand decatherms (of natural gas)
MMBtu	Million British thermal units
MMcf	Million cubic feet (of natural gas)
NGA	The Natural Gas Act of 1938, as amended; the federal law regulating interstate natural gas pipeline and storage companies, among other things, codified beginning at 15 U.S.C. Section 717.
NYMEX	New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.
Open Season	A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.
Precedent Agreement	An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called "conditions precedent") happen, usually within a specified time.

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Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped (PUD) reserves	Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make these reserves productive.
Reserves	The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.
Revenue decoupling mechanism	A rate mechanism which adjusts customer rates to render a utility financially indifferent to throughput decreases resulting from conservation.
S&P	Standard & Poor’s Rating Service
SAR	Stock appreciation right
Service agreement	

	The binding agreement by which the pipeline company agrees to provide service and the shipper agrees to pay for the service.
Stock acquisitions	Investments in corporations
VEBA	Voluntary Employees' Beneficiary Association
WNC	Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs

will be
recovered.

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•The Company has nothing to report under this item.

Reference to "the Company" in this report means the Registrant or the Registrant and its subsidiaries collectively, as appropriate in the context of the disclosure. All references to a certain year in this report are to the Company’s fiscal year ended September 30 of that year, unless otherwise noted.

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Part I. Financial Information

Item 1. Financial Statements

National Fuel Gas Company

Consolidated Statements of Income and Earnings

Reinvested in the Business

(Unaudited)

	Three Months Ended December 31,	
(Thousands of Dollars, Except Per Common Share Amounts)	2012	2011
INCOME		
Operating Revenues	$ 452,854	$ 432,423
Operating Expenses		
Purchased Gas	121,919	132,193
Operation and Maintenance	107,732	100,059
Property, Franchise and Other Taxes	19,664	19,230
Depreciation, Depletion and Amortization	72,331	62,547
	321,646	314,029
Operating Income	131,208	118,394
Other Income (Expense):		
Interest Income	1,386	1,105
Other Income	1,415	1,336
Interest Expense on Long-Term Debt	(21,448)	(18,641)
Other Interest Expense	(1,068)	(770)
Income Before Income Taxes	111,493	101,424
Income Tax Expense	43,549	40,725
Net Income Available for Common Stock	67,944	60,699
EARNINGS REINVESTED IN THE BUSINESS		
Balance at October 1	1,306,284	1,206,022
	1,374,228	1,266,721
Dividends on Common Stock		
(2012 - $0.365 per share; 2011 - $0.355 per share)	(30,463)	(29,479)
Balance at December 31	$ 1,343,765	$ 1,237,242

Earnings Per Common Share:		
Basic:		
Net Income Available for Common Stock	$ 0.81	$ 0.73
Diluted:		
Net Income Available for Common Stock	$ 0.81	$ 0.73
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	83,390,278	82,870,931
Used in Diluted Calculation	84,006,050	83,699,981

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Statements of Comprehensive Income

(Unaudited)

(Thousands of Dollars)	Three Months Ended December 31, 2012	2011
Net Income Available for Common Stock	$ 67,944	$ 60,699
Other Comprehensive Income (Loss), Before Tax:		
Unrealized Gain on Securities Available for Sale Arising During the Period	789	712
Unrealized Gain on Derivative Financial Instruments Arising During the Period	35,350	2,155
Reclassification Adjustment for Realized Gains on Derivative Financial Instruments in Net Income	(11,584)	(11,864)
Other Comprehensive Income (Loss) Before Tax	24,555	(8,997)
Income Tax Expense Related to Unrealized Gain On Securities Available for Sale Arising During the Period	295	263
Income Tax Expense Related to Unrealized Gain on Derivative Financial Instruments Arising During the Period	14,738	817
Reclassification Adjustment for Income Tax Expense on Realized Gains from Derivative Financial Instruments In Net Income	(4,854)	(4,644)
Income Taxes – Net	10,179	(3,564)
Other Comprehensive Income (Loss)	14,376	(5,433)
Comprehensive Income	$ 82,320	$ 55,266

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Balance Sheets

(Unaudited)

	December 31, 2012	September 30, 2012
(Thousands of Dollars)		
ASSETS		
Property, Plant and Equipment	$ 6,791,637	$ 6,615,813
Less - Accumulated Depreciation, Depletion and Amortization	1,935,448	1,876,010
	4,856,189	4,739,803
Current Assets		
Cash and Temporary Cash Investments	61,017	74,494
Hedging Collateral Deposits	-	364
Receivables – Net of Allowance for Uncollectible Accounts of $34,030 and $30,317, Respectively	143,567	115,818
Unbilled Utility Revenue	47,134	19,652
Gas Stored Underground	44,485	49,795
Materials and Supplies - at average cost	29,946	28,577
Other Current Assets	49,108	56,121
Deferred Income Taxes	19,112	10,755
	394,369	355,576
Other Assets		
Recoverable Future Taxes	152,202	150,941
Unamortized Debt Expense	12,860	13,409
Other Regulatory Assets	551,707	546,851
Deferred Charges	6,781	7,591
Other Investments	90,513	86,774
Goodwill	5,476	5,476
Fair Value of Derivative Financial Instruments	37,135	27,616
Other	965	1,105
	857,639	839,763
Total Assets	$ 6,108,197	$ 5,935,142

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Balance Sheets

(Unaudited)

(Thousands of Dollars)	December 31, 2012	September 30, 2012
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value Authorized - 200,000,000 Shares; Issued And Outstanding – 83,482,125 Shares and 83,330,140 Shares, Respectively	$ 83,482	$ 83,330
Paid in Capital	673,607	669,501
Earnings Reinvested in the Business	1,343,765	1,306,284
Total Common Shareholders' Equity Before Items of Other Comprehensive Loss	2,100,854	2,059,115
Accumulated Other Comprehensive Loss	(84,644)	(99,020)
Total Comprehensive Shareholders' Equity	2,016,210	1,960,095
Long-Term Debt, Net of Current Portion	1,149,000	1,149,000
Total Capitalization	3,165,210	3,109,095
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	238,000	171,000
Current Portion of Long-Term Debt	250,000	250,000
Accounts Payable	94,909	87,985
Amounts Payable to Customers	15,278	19,964
Dividends Payable	-	30,416
Interest Payable on Long-Term Debt	16,320	29,491
Customer Advances	22,068	24,055
Customer Security Deposits	18,926	17,942
Other Accruals and Current Liabilities	103,582	79,099
Fair Value of Derivative Financial Instruments	13,816	24,527
	772,899	734,479
Deferred Credits		
Deferred Income Taxes	1,126,551	1,065,757
Taxes Refundable to Customers	66,396	66,392
Unamortized Investment Tax Credit	1,898	2,005

Cost of Removal Regulatory Liability	147,267	139,611
Other Regulatory Liabilities	22,911	21,014
Pension and Other Post-Retirement Liabilities	514,116	516,197
Asset Retirement Obligations	123,984	119,246
Other Deferred Credits	166,965	161,346
	2,170,088	2,091,568
Commitments and Contingencies	-	-
Total Capitalization and Liabilities	$ 6,108,197	$ 5,935,142

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Statements of Cash Flows

(Unaudited)

(Thousands of Dollars)	Three Months Ended December 31, 2012	2011
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$ 67,944	$ 60,699
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	72,331	62,547
Deferred Income Taxes	41,000	39,398
Other	7,923	2,375
Change in:		
Hedging Collateral Deposits	364	(5,417)
Receivables and Unbilled Utility Revenue	(55,261)	(51,054)
Gas Stored Underground and Materials and Supplies	3,941	(2,226)
Unrecovered Purchased Gas Costs	-	(3,002)
Other Current Assets	7,013	232
Accounts Payable	6,163	(5,065)
Amounts Payable to Customers	(4,686)	(3,522)
Customer Advances	(1,987)	6,171
Customer Security Deposits	984	364
Other Accruals and Current Liabilities	(5,667)	(3,460)
Other Assets	(597)	(6,244)
Other Liabilities	6,495	3,867
Net Cash Provided by Operating Activities	145,960	95,663
INVESTING ACTIVITIES		
Capital Expenditures	(162,981)	(249,105)
Other	(3,533)	(966)
Net Cash Used in Investing Activities	(166,514)	(250,071)
FINANCING ACTIVITIES		
Changes in Notes Payable to Banks and Commercial Paper	67,000	(20,000)
Net Proceeds from Issuance of Long-Term Debt	-	496,085
Reduction of Long-Term Debt	-	(150,000)
Dividends Paid on Common Stock	(60,879)	(29,398)
Net Proceeds from Issuance of Common Stock	956	1,555

Net Cash Provided by Financing Activities	7,077	298,242
Net Increase (Decrease) in Cash and Temporary Cash Investments	(13,477)	143,834
Cash and Temporary Cash Investments at October 1	74,494	80,428
Cash and Temporary Cash Investments at December 31	$ 61,017	$ 224,262

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Notes to Condensed Consolidated Financial Statements

(Unaudited)

Note 1 - Summary of Significant Accounting Policies

Principles of Consolidation. The Company consolidates all entities in which it has a controlling financial interest. All significant intercompany balances and transactions are eliminated.

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications and Revisions. Certain prior year amounts have been reclassified to conform with current year presentation.

Revisions were made on the Consolidated Statement of Cash Flows for the quarter ended December 31, 2011 to reflect non-cash investing activities embedded in Accounts Payable on the Consolidated Balance Sheets at December 31, 2011 and September 30, 2011. These revisions increased the operating cash flows related to the change in Accounts Payable for the quarter ended December 31, 2011 by $16.4 million and decreased investing cash flows related to Capital Expenditures by the same amounts.

In subsequent periods, revisions will be made on the Consolidated Statement of Cash Flows for the six months ended March 31, 2012, the nine months ended June 30, 2012 and the fiscal years ended September 30, 2012 and September 30, 2011 to reflect non-cash investing activities embedded in Accounts Payable on the Consolidated Balance Sheets for the respective periods. These revisions will increase the operating cash flows related to the six months ended March 31, 2012 and the nine months ended June 30, 2012 by $17.7 million and $32.8 million, respectively, and decrease investing cash flows related to Capital Expenditures by the same amount. The revision for the fiscal years ended September 30, 2012 and September 30, 2011 will decrease operating cash flows by $1.8 million and $6.6 million, respectively, and increase investing cash flows related to Capital Expenditures by the same amounts. The revisions in the Consolidated Statement of Cash Flows noted above represent errors that are not deemed material, individually or in the aggregate, to the prior period consolidated financial statements.

Earnings for Interim Periods. The Company, in its opinion, has included all adjustments that are necessary for a fair statement of the results of operations for the reported periods. The consolidated financial statements and notes thereto, included herein, should be read in conjunction with the financial statements and notes for the years ended September 30, 2012, 2011 and 2010 that are included in the Company's 2012 Form 10-K. The consolidated financial statements for the year ended September 30, 2013 will be audited by the Company's independent registered public accounting firm after the end of the fiscal year.

The earnings for the three months ended December 31, 2012 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2013. Most of the business of the Utility and Energy Marketing segments is seasonal in nature and is influenced by weather conditions. Due to the seasonal nature of the heating business in the Utility and Energy Marketing segments, earnings during the winter months normally represent a substantial part of the earnings that those segments are expected to achieve for the entire fiscal year. The Company’s business segments are discussed more fully in Note 7 – Business Segment Information.

Consolidated Statement of Cash Flows. For purposes of the Consolidated Statement of Cash Flows, the Company considers all highly liquid debt instruments purchased with a maturity of generally three months or less to be cash equivalents.

The Company has accounts payable and accrued liabilities recorded on its Consolidated Balance Sheets that are related to capital expenditures. These amounts represent non-cash investing activities at the

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balance sheet date. Accordingly, they are excluded from the Consolidated Statement of Cash Flows when they are recorded as liabilities and included in the Consolidated Statement of Cash Flows when they are paid in the subsequent period. The following table summarizes the Company's non-cash capital expenditures recorded as Accounts Payable and Other Accruals and Current Liabilities on the Consolidated Balance Sheet:

	At December 31,		At September 30,	
	2012	2011	2012	2011
	(Thousands)			
Non-cash Capital Expenditures	$86,144	$154,960	$67,503	$ 125,115

Hedging Collateral Deposits. This is an account title for cash held in margin accounts funded by the Company to serve as collateral for hedging positions. At December 31, 2012 the Company did not have any hedging collateral deposits, but at September 30, 2012, it had hedging collateral deposits of $0.4 million related to its exchange-traded futures contracts. In accordance with its accounting policy, the Company does not offset hedging collateral deposits paid or received against related derivative financial instruments liability or asset balances.

Gas Stored Underground - Current. In the Utility segment, gas stored underground – current is carried at lower of cost or market, on a LIFO method. Gas stored underground – current normally declines during the first and second quarters of the year and is replenished during the third and fourth quarters. In the Utility segment, the current cost of replacing gas withdrawn from storage is recorded in the Consolidated Statements of Income and a reserve for gas replacement is recorded in the Consolidated Balance Sheets under the caption "Other Accruals and Current Liabilities." Such reserve, which amounted to $6.7 million at December 31, 2012, is reduced to zero by September 30 of each year as the inventory is replenished.

Property, Plant and Equipment. In the Company's Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Under this methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities. The Company does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center.

Capitalized costs include costs related to unproved properties, which are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. Such costs amounted to $155.6 million and $146.1 million at December 31, 2012 and September 30, 2012, respectively. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The natural gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. At December 31, 2012, the ceiling exceeded the book value of the oil and gas properties by approximately $7.3 million.

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Accumulated Other Comprehensive Loss. The components of Accumulated Other Comprehensive Loss, net of related tax effect, are as follows (in thousands):

	At December 31, 2012	At September 30, 2012
Funded Status of the Pension and the Post-Retirement Benefit Plans	$ (100,561)	$ (100,561)
Net Unrealized Gain (Loss) on Derivative Financial Instruments	12,280	(1,602)
Net Unrealized Gain on Securities Available for Sale	3,637	3,143
Accumulated Other Comprehensive Loss	$ (84,644)	$ (99,020)

Other Current Assets. The components of the Company's Other Current Assets are as follows (in thousands):

	At December 31, 2012	At September 30, 2012
	$	$
Prepayments	6,168	8,316
Prepaid Property and Other Taxes	15,295	14,455
Federal Income Taxes Receivable	268	268
State Income Taxes Receivable	-	2,065

Fair Values of Firm Commitments	2,535	1,291
Regulatory Assets	24,842	29,726
	$ 49,108	$ 56,121

Other Accruals and Current Liabilities. The components of the Company's Other Accruals and Current Liabilities are as follows (in thousands):

	At December 31, 2012	At September 30, 2012
Accrued Capital Expenditures	$ 54,339	$ 36,460
Regulatory Liabilities	16,207	18,289
Reserve for Gas Replacement	6,718	-
Other	26,318	24,350
	$ 103,582	$ 79,099

Earnings Per Common Share. Basic earnings per common share is computed by dividing net income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the only potentially dilutive securities the Company has outstanding are stock options, SARs and restricted stock units. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these securities as determined using the Treasury Stock Method. Stock options, SARs and restricted stock units that are antidilutive are excluded from the calculation of diluted earnings per common share. There were 422,681 and 191,285 securities excluded as being antidilutive for the quarters ended December 31, 2012 and 2011, respectively.

Stock-Based Compensation. During the quarter ended December 31, 2012, the Company granted 412,970 non-performance based SARs having a weighted average exercise price of $53.05 per share. The weighted average grant date fair value of these SARs was $10.66 per share. These SARs may be settled in cash, in shares of common stock of the Company, or in a combination of cash and shares of common stock of the Company, as determined by the Company. These SARs are considered equity awards under the current authoritative guidance for stock-based compensation. The accounting for those SARs is the same as the accounting for stock options. The non-performance based SARs granted during the quarter ended December 31, 2012 vest and become exercisable annually in one-third increments. The weighted average grant date fair value of these non-performance based SARs granted during the quarter ended December 31,

2012 was estimated on the date of grant using the same accounting treatment that is applied for stock options. There were no stock options granted during the quarter ended December 31, 2012.

The Company granted 210,206 performance based restricted stock units during the quarter ended December 31, 2012. The weighted average fair value of such performance based restricted stock units was $48.49 per share for the quarter ended December 31, 2012. The performance based restricted stock units granted during the quarter ended December 31, 2012 must meet a performance condition over the performance cycle of October 1, 2012 to September 30, 2015. The performance condition over the performance cycle, generally stated, is the Company's total return on capital as compared to the same metric for companies in the Natural Gas Distribution and Integrated Natural Gas Companies group as calculated and reported in the Monthly Utility Reports of AUS, Inc., a leading industry consultant. The number of performance based restricted stock units that will vest will depend upon the Company's performance relative to the report group and not upon the absolute level of return achieved by the Company. The Company also granted 26,100 non-performance based restricted stock units during the quarter ended December 31, 2012. The weighted average fair value of such non-performance based restricted stock units was $47.20 per share for the quarter ended December 31, 2012. Restricted stock units, both performance based and non-performance based, represent the right to receive shares of common stock of the Company (or the equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company) at the end of a specified time period. The performance based and non-performance based restricted stock units do not entitle the participant to receive dividends during the vesting period. The accounting for performance based and non-performance based restricted stock units is the same as the accounting for restricted share awards, except that the fair value at the date of grant of the restricted stock units must be reduced by the present value of forgone dividends over the vesting term of the award. There were no restricted share awards granted during the quarter ended December 31, 2012.

New Authoritative Accounting and Financial Reporting Guidance. In June 2011, the FASB issued authoritative guidance regarding the presentation of comprehensive income. The new guidance allows companies only two choices for presenting net income and other comprehensive income: in a single continuous statement, or in two separate, but consecutive, statements. The guidance eliminates the option to report other comprehensive income and its components in the statement of changes in equity. This authoritative guidance became effective for the quarter ended December 31, 2012. The Company has updated its financial statements to reflect the new guidance.

In December 2011, the FASB issued authoritative guidance requiring enhanced disclosures regarding offsetting assets and liabilities. Companies are required to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2014 and is not expected to have a significant impact on the Company's financial statements.

Note 2 – Fair Value Measurements

The FASB authoritative guidance regarding fair value measurements establishes a fair-value hierarchy and prioritizes the inputs used in valuation techniques that measure fair value. Those inputs are prioritized into three levels. Level 1 inputs are unadjusted quoted prices in active markets for assets or liabilities that the Company can access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly at the measurement date. Level 3 inputs are unobservable inputs for the asset or liability at the measurement date. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of December 31, 2012 and September 30, 2012. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

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Recurring Fair Value Measures	At fair value as of December 31, 2012				
				Netting Adjustments[1]	
(Thousands of Dollars)	Level 1	Level 2	Level 3		Total
Assets:					
Cash Equivalents – Money Market Mutual Funds	$ 33,215	$ -	$ -	$ -	$ 33,215
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	2,841	-	-	(2,211)	630
Over the Counter Swaps – Oil	-	186	719	(1,332)	(427)
Over the Counter Swaps – Gas	-	58,983	-	(22,051)	36,932
Other Investments:					
Balanced Equity Mutual Fund	28,586	-	-	-	28,586
Common Stock – Financial Services Industry	5,371	-	-	-	5,371
Other Common Stock	273	-	-	-	273
Total	$ 70,286	$ 59,169	$ 719	$ (25,594)	$ 104,580
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$ 2,211	$ -	$ -	$ (2,211)	$ -
Over the Counter Swaps – Oil	-	1,133	14,808	(1,332)	14,609
Over the Counter Swaps – Gas	-	21,258	-	(22,051)	(793)
Total	$ 2,211	$ 22,391	$ 14,808	$ (25,594)	$ 13,816
Total Net Assets/(Liabilities)	$ 68,075	$ 36,778	$ (14,089)	$ -	$ 90,764

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Recurring Fair Value Measures	At fair value as of September 30, 2012				
				Netting Adjustments[1]	
(Thousands of Dollars)	Level 1	Level 2	Level 3		Total
Assets:					

Cash Equivalents – Money Market Mutual Funds	$ 46,113	$ -	$ -	$ -	$ 46,113
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	4,348	-	-	(2,760)	1,588
Over the Counter Swaps – Gas	-	41,751	-	(15,723)	26,028
Over the Counter Swaps – Oil	-	-	559	(559)	-
Other Investments:					
Balanced Equity Mutual Fund	24,767	-	-	-	24,767
Common Stock – Financial Services Industry	4,758	-	-	-	4,758
Other Common Stock	272	-	-	-	272
Hedging Collateral Deposits	364	-	-	-	364
Total	$ 80,622	$ 41,751	$ 559	$ (19,042)	$ 103,890
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$ 2,760	$ -	$ -	(2,760)	$ -
Over the Counter Swaps – Gas	-	19,932	-	(15,723)	4,209
Over the Counter Swaps – Oil	-	654	20,223	(559)	20,318
Total	$ 2,760	$ 20,586	$ 20,223	$ (19,042)	$ 24,527
Total Net Assets/(Liabilities)	$ 77,862	$ 21,165	$ (19,664)	$ -	$ 79,363

(1) Amounts represent the impact of legally-enforceable master netting arrangements that allow the Company to net gain and loss positions held with the same counterparties.

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Derivative Financial Instruments

At December 31, 2012 and September 30, 2012, the derivative financial instruments reported in Level 1 consist of natural gas NYMEX futures contracts used in the Company's Energy Marketing segment. Hedging collateral deposits of $0.4 million (at September 30, 2012), which are associated with these futures contracts, have been reported in Level 1 as well (there were no hedging collateral deposits at December 31, 2012). The derivative financial instruments reported in Level 2 at December 31, 2012 and September 30, 2012 consist of natural gas price swap agreements used in the Company's Exploration and Production and Energy Marketing segments and some of the crude oil price swap agreements used in the Company's Exploration and Production segment. The fair value of the Level 2 price swap agreements is based on an internal, discounted cash flow model that uses observable inputs (i.e. LIBOR based discount rates and basis differential information, if applicable, at active natural gas and crude oil trading markets). The derivative financial instruments reported in Level 3 consist of the majority of the Company's Exploration and Production segment's crude oil price swap agreements at December 31, 2012 and September 30, 2012. The fair value of the Level 3 crude oil price swap agreements is based on an internal, discounted cash flow model that uses both observable (i.e. LIBOR based discount rates) and unobservable inputs (i.e. basis differential information of crude oil trading markets with low trading volume).

The significant unobservable input used in the fair value measurement of the majority of the Company's over-the-counter crude oil swaps is the basis differential between Midway Sunset oil and NYMEX contracts. Significant changes in the assumed basis differential could result in a significant change in value of the derivative financial instruments. At December 31, 2012, it was assumed that Midway Sunset oil was 109.6% of NYMEX. This is based on a historical twelve month average of Midway Sunset oil sales verses NYMEX settlements. During this twelve-month period, the price of Midway Sunset oil ranged from 103.2% to 112.4% of NYMEX. If the basis differential between Midway Sunset oil and NYMEX contracts used in the fair value measurement calculation at December 31, 2012 had been 10 percentage points lower, the fair value of the Level 3 crude oil price swap agreements would have changed from a net liability of $14.1 million to a net asset of $2.0 million. If the basis differential between Midway Sunset oil and NYMEX contracts used in the fair value measurement at December 31, 2012 had been 10 percentage points higher, the fair value measurement of the Level 3 crude oil price swap agreements liability would have been approximately $16.1 million higher. These calculated amounts are based solely on basis differential changes and do not take into account any other changes to the fair value measurement calculation.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At December 31, 2012, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty (for an asset) or the Company's (for a liability) credit default swaps rates.

The tables listed below provide reconciliations of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3 for the quarters ended December 31, 2012 and 2011, respectively. For the quarters ended December 31, 2012 and December 31, 2011, no transfers in or out of Level 1 or Level 2 occurred. There were no purchases or sales of derivative financial instruments during the periods presented in the tables below. All settlements of the derivative financial instruments are reflected in the Gains/Losses Realized and Included in Earnings column of the tables below.

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Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)	October 1, 2012	Total Gains/Losses (Gains)/ Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	December 31, 2012
Derivative Financial Instruments[2]	$ (19,664)	$2,261[1]	$ 3,314	$ -	$ (14,089)

[1] Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended December 31, 2012.

[2] Derivative Financial Instruments are shown on a net basis.

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)	October 1, 2011	Total Gains/Losses (Gains)/ Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	December 31, 2011
Derivative Financial Instruments[2]	$(5,410)	$12,612[1]	$(61,975)	$ -	$(54,773)

[1] Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended December 31, 2011.

[2] Derivative Financial Instruments are shown on a net basis.

Note 3 – Financial Instruments

Long-Term Debt. The fair market value of the Company's debt, as presented in the table below, was determined using a discounted cash flow model, which incorporates the Company's credit ratings and current market conditions in determining the yield, and subsequently, the fair market value of the debt. Based on these criteria, the fair market value of long-term debt, including current portion, was as follows (in thousands):

	December 31, 2012		September 30, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$1,399,000	$1,617,781	$1,399,000	$1,623,847

The fair value amounts are not intended to reflect principal amounts that the Company will ultimately be required to pay. Carrying amounts for other financial instruments recorded on the Company's Consolidated Balance Sheets approximate fair value. The fair value of long-term debt was calculated using observable inputs (U.S. Treasuries/LIBOR for the risk free component and company specific credit spread information – generally obtained from recent trade activity in the debt). As such, the Company considers the debt to be Level 2.

Temporary cash investments, notes payable to banks and commercial paper are stated at cost. Temporary cash investments are considered Level 1, while notes payable to banks and commercial paper are considered to be Level 2. Given the short-term nature of the notes payable to banks and commercial paper, the Company believes cost is a reasonable approximation of fair value.

Other Investments. Investments in life insurance are stated at their cash surrender values or net present value as discussed below. Investments in an equity mutual fund and the stock of an insurance company (marketable equity securities), as discussed below, are stated at fair value based on quoted market prices.

Other investments include cash surrender values of insurance contracts (net present value in the case of split-dollar collateral assignment arrangements) and marketable equity securities. The values of the insurance contracts amounted to $56.3 million and $57.0 million at December 31, 2012 and September 30, 2012, respectively. The fair value of the equity mutual fund was $28.6 million at December 31, 2012 and $24.8 million at September 30, 2012. The gross unrealized gain on this equity mutual fund was $2.7 million

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at December 31, 2012 and $2.6 million at September 30, 2012. The fair value of the stock of an insurance company was $5.4 million at December 31, 2012 and $4.8 million at September 30, 2012. The gross unrealized gain on this stock was $3.0 million at December 31, 2012 and $2.3 million at September 30, 2012. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments. The Company uses or has used derivative instruments to manage commodity price risk in the Exploration and Production, Energy Marketing, and Pipeline and Storage segments. The Company enters into futures contracts and over-the-counter swap agreements for natural gas and crude oil to manage the price risk associated with forecasted sales of gas and oil. The Company also enters into futures contracts and swaps to manage the risk associated with forecasted gas purchases, forecasted gas sales, storage of gas, withdrawal of gas from storage to meet customer demand and the potential decline in the value of gas held in storage. The duration of the Company's hedges does not typically exceed 5 years.

The Company has presented its net derivative assets and liabilities as "Fair Value of Derivative Financial Instruments" on its Consolidated Balance Sheets at December 31, 2012 and September 30, 2012. All of the derivative financial instruments reported on those line items related to commodity contracts as discussed in the paragraph above.

Cash flow hedges

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income (loss) and reclassified into earnings in the period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

As of December 31, 2012, the Company's Exploration and Production segment had the following commodity derivative contracts (swaps) outstanding to hedge forecasted sales (where the Company uses short positions (i.e. positions that pay-off in the event of commodity price decline) to mitigate the risk of decreasing revenues and earnings):

Commodity	Units
Natural Gas	130.5 Bcf (all short positions)
Crude Oil	2,541,000 Bbls (all short positions)

As of December 31, 2012, the Company's Energy Marketing segment had the following commodity derivative contracts (futures contracts and swaps) outstanding to hedge forecasted sales (where the Company uses short positions to mitigate the risk associated with natural gas price decreases and its impact on decreasing revenues and earnings) and, when applicable, purchases (where the Company uses long positions (i.e. positions that pay-off in the event of commodity price increases) to mitigate the risk of increasing natural gas prices, which would lead to increased purchased gas expense and decreased earnings):

Commodity	Units
Natural Gas	5.8 Bcf (4.4 Bcf short positions (mostly forecasted storage withdrawals) and 1.4 Bcf long positions (mostly forecasted storage injections))

As of December 31, 2012, the Company's Exploration and Production segment had $22.2 million ($12.9 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $40.0 million ($23.3 million after tax) of such unrealized gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the expected sales of the underlying commodities occur. It is expected that unrealized losses will be reclassified into the Consolidated Statement of Income in subsequent periods as the expected sales of the underlying commodities occur.

As of December 31, 2012, the Company's Energy Marketing segment had $1.0 million ($0.6 million after tax) of net hedging losses included in the accumulated other comprehensive income (loss) balance. It is expected that $0.9 million ($0.6 million after tax) of these losses will be reclassified into the Consolidated

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Statement of Income (Loss) within the next 12 months as the expected sales of the underlying commodity occurs.

Refer to Note 1, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain (loss) pertaining to derivative financial instruments for the Exploration and Production and Energy Marketing segments.

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the

Three Months Ended December 31, 2012 and 2011 (Thousands of Dollars)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Three Months Ended December 31,		Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Three Months Ended December 31,		Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) for the Three Months Ended December 31,	
	2012	2011		2012	2011		2012	2011

Commodity Contracts – Exploration & Production segment								
			Operating Revenue			Not		
	$33,615	$(3,923)		$12,304	$ 5,420	Applicable	$ -	$ -
Commodity Contracts – Energy Marketing segment								
						Not		
	$ 1,735	$ 6,078	Purchased Gas	$ (48)	$ 6,444	Applicable	$ -	$ -
Commodity Contracts – Pipeline & Storage segment(1)								
			Operating Revenue			Not		
	$ -	$ -		$ (672)	$ -	Applicable	$ -	$ -
Total	$35,350	$2,155		$11,584	$11,864		$ -	$ -

(1) There were no open hedging positions at December 31, 2012 or 2011.

Fair value hedges

The Company's Energy Marketing segment utilizes fair value hedges to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in the value of certain natural gas held in storage. With respect to fixed price sales commitments, the Company enters into long

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positions to mitigate the risk of price increases for natural gas supplies that could occur after the Company enters into fixed price sales agreements with its customers. With respect to fixed price purchase commitments, the Company enters into short positions to mitigate the risk of price decreases that could occur after the Company locks into fixed price purchase deals with its suppliers. With respect to storage hedges, the Company enters into short positions to mitigate the risk of price decreases that could result in a lower of cost or market writedown of the value of natural gas in storage that is recorded in the Company's financial statements. As of December 31, 2012, the Company's Energy Marketing segment had fair value hedges covering approximately 9.1 Bcf (8.0 Bcf of fixed price sales commitments (mostly long positions), 0.9 Bcf of fixed price purchase commitments (mostly short positions) and 0.2 Bcf of commitments related to the withdrawal of storage gas (all short positions)). For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

Derivatives in Fair Value Hedging Relationships – Energy Marketing segment	Location of Gain or (Loss) on Derivative and Hedged Item Recognized in the Consolidated Statement of Income	Amount of Gain or (Loss) on Derivative Recognized in the Consolidated Statement of Income for the Three Months Ended December 31, 2012 (In Thousands)	Amount of Gain or (Loss) on the Hedged Item Recognized in the Consolidated Statement of Income for the Three Months Ended December 31, 2012 (In Thousands)
Commodity Contracts – Hedge of fixed price sales commitments of natural gas	Operating Revenues	$ (1,678)	$ 1,678
Commodity Contracts – Hedge of fixed price purchase commitments of natural gas	Purchased Gas	$ 9	$ (9)
Commodity Contracts – Hedge of natural gas held in storage	Purchased Gas	$ 64	$ (64)
		$ (1,605)	$ 1,605

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company's counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with eleven counterparties of which eight are in a net gain position. On average, the Company had $4.5 million of credit exposure per counterparty in a gain position at December 31, 2012. The maximum credit exposure per counterparty in a gain position at December 31, 2012 was $11.1 million. As of December 31, 2012, the Company had not received any collateral from the counterparties. The Company's gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral, nor had the counterparties' credit ratings declined to levels at which the counterparties were required to post collateral.

As of December 31, 2012, nine of the eleven counterparties to the Company's outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk related contingency feature. In the event the Company's credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company's credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company's outstanding derivative instrument contracts were in a liability position (or if the current liability were larger) and/or the Company's credit rating declined, then additional hedging collateral deposits may be required. At December 31, 2012, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $23.8 million according to the Company's internal model (discussed in Note 2 — Fair Value Measurements). At December 31, 2012, the fair market value of the

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derivative financial instrument liabilities with a credit-risk related contingency feature was $13.8 million according to the Company’s internal model (discussed in Note 2 — Fair Value Measurements). For its over-the-counter crude oil swap agreements, which were in a liability position, the Company was not required to post any hedging collateral deposits at December 31, 2012.

For its exchange traded futures contracts, which are in an asset position, the Company was not required to post any hedging collateral deposits as of December 31, 2012. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions and margin requirements it has with its counterparties.

The Company’s requirement to post hedging collateral deposits is based on the fair value determined by the Company’s counterparties, which may differ from the Company’s assessment of fair value. Hedging collateral deposits may also include closed derivative positions in which the broker has not cleared the cash from the account to offset the derivative liability. The Company records liabilities related to closed derivative positions in Other Accruals and Current Liabilities on the Consolidated Balance Sheet. These liabilities are relieved when the broker clears the cash from the hedging collateral deposit account. This is discussed in Note 1 under Hedging Collateral Deposits.

Note 4 - Income Taxes

The components of federal and state income taxes included in the Consolidated Statements of Income are as follows (in thousands):

	Three Months Ended December 31,	
	2012	2011
Current Income Taxes		
Federal	$ -	$ (7)
State	2,549	1,334
Deferred Income Taxes		
Federal	34,903	31,338
State	6,097	8,060
	43,549	40,725
Deferred Investment Tax Credit	(107)	(145)

Total Income Taxes	$ 43,442	$ 40,580
Presented as Follows:		
Other Income	$ (107)	$ (145)
Income Tax Expense	43,549	40,725
Total Income Taxes	$ 43,442	$ 40,580

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Total income taxes as reported differ from the amounts that were computed by applying the federal income tax rate to income before income taxes. The following is a reconciliation of this difference (in thousands):

	Three Months Ended December 31,	
	2012	2011
U.S. Income Before Income Taxes	$ 111,386	$ 101,279
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	$ 38,985	$ 35,448
Increase (Reduction) in Taxes Resulting from:		
State Income Taxes	5,620	6,106
Miscellaneous	(1,163)	(974)
Total Income Taxes	$ 43,442	$ 40,580

Significant components of the Company’s deferred tax liabilities and assets were as follows (in thousands):

	At December 31, 2012	At September 30, 2012
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 1,365,011	$ 1,333,574
Pension and Other Post-Retirement Benefit Costs	240,380	236,431
Other	52,468	43,294
Total Deferred Tax Liabilities	1,657,859	1,613,299
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(274,649)	(276,501)
Tax Loss Carryforwards	(192,412)	(198,744)
Other	(83,359)	(83,052)
Total Deferred Tax Assets	(550,420)	(558,297)
Total Net Deferred Income Taxes	$ 1,107,439	$ 1,055,002

Presented as Follows:		
Net Deferred Tax Liability/(Asset) – Current	$ (19,112)	$ (10,755)
Net Deferred Tax Liability – Non-Current	1,126,551	1,065,757
Total Net Deferred Income Taxes	$ 1,107,439	$ 1,055,002

As a result of certain realization requirements of the authoritative guidance on stock-based compensation, the table of deferred tax liabilities and assets shown above does not include certain deferred tax assets that arose directly from excess tax deductions related to stock-based compensation. Cumulative tax benefits of $37.5 million and $32.7 million for the periods ending December 31, 2012 and September 30, 2012, respectively, relating to the excess stock-based compensation deductions will be recorded in Paid in Capital in future years when such tax benefits are realized.

Regulatory liabilities representing the reduction of previously recorded deferred income taxes associated with rate-regulated activities that are expected to be refundable to customers amounted to $66.4 million at December 31, 2012 and September 30, 2012. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of prior ratemaking practices, amounted to $152.2 million and $150.9 million at December 31, 2012 and September 30, 2012, respectively.

The Internal Revenue Service (IRS) is currently conducting examinations of the Company for fiscal 2011 and fiscal 2012 in accordance with the Compliance Assurance Process (“CAP”). The CAP audit employs a real time review of the Company’s books and tax records by the IRS that is intended to permit issue resolution prior to the filing of the tax return. While the federal statute of limitations remains open for fiscal 2009 and later years, IRS examinations for fiscal 2008 and prior years have been completed and the Company believes such years are effectively settled. During fiscal 2009, consent was received from the IRS National Office approving the Company’s application to change its tax method of accounting for certain capitalized costs relating to its utility property. Local IRS examiners proposed to disallow most of the tax accounting method change recorded by the Company in fiscal 2009 and fiscal 2010. The Company has filed protests for fiscal 2009 and fiscal 2010 with the IRS Appeals Office disputing the local IRS findings. The local IRS examiners have again considered this issue to be unresolved for fiscal 2011 and will conduct a post-filing examination of this issue upon the anticipated issuance of IRS guidance addressing this issue for natural gas utilities.

The Company is also subject to various routine state income tax examinations. The Company’s principal subsidiaries operate mainly in four states which have statutes of limitations that generally expire between three to four years from the date of filing of the income tax return.

On January 2, 2013, President Obama signed into law the American Taxpayer Relief Act of 2012 (the Relief Act). As a result of ongoing IRS examinations, it is uncertain whether the Relief Act will have a material effect on the Company’s financial statements.

Note 5 - Capitalization

Common Stock. During the three months ended December 31, 2012, the Company issued 342,822 original issue shares of common stock as a result of stock option and SARs exercises. In addition, the Company issued 60,631 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan. The Company also issued 4,050 original issue shares of common stock to the non-employee directors of the Company who receive compensation under the Company’s 2009 Non-Employee Director Equity Compensation Plan, as partial consideration for the directors’ services during the three months ended December 31, 2012. Holders of stock options, SARs or restricted stock will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During the three months ended December 31, 2012, 255,518 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

Current Portion of Long-Term Debt. Current Portion of Long-Term Debt at both December 31, 2012 and September 30, 2012 consisted of $250 million of 5.25% notes that mature in March 2013.

Note 6 - Commitments and Contingencies

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory policies and procedures. It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs.

The Company has agreed with the NYDEC to remediate a former manufactured gas plant site located in New York. In February 2009, the Company received approval from the NYDEC of a Remedial Design Work Plan (RDWP) for this site. In October 2010, the Company submitted a RDWP addendum to conduct additional Preliminary Design Investigation field activities necessary to design a successful remediation. An estimated minimum liability for remediation of this site of $14.0 million has been recorded.

At December 31, 2012, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites (including the former manufactured gas

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plant site discussed above) will be in the range of $16.3 million to $21.9 million. The minimum estimated liability of $16.3 million, which includes the $14.0 million discussed above, has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at December 31, 2012. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 11 years.

The Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental laws and regulations, new information or other factors could adversely impact the Company.

Other. The Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations and other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these other matters arising in the normal course of business could have a material effect on earnings and cash flows in the period in which they are resolved, an estimate of the possible loss or range of loss, if any, cannot be made at this time.

Note 7 – Business Segment Information

The Company reports financial results for four segments: Utility, Pipeline and Storage, Exploration and Production, and Energy Marketing. The division of the Company’s operations into reportable segments is based upon a combination of factors including differences in products and services, regulatory environment and geographic factors.

The data presented in the tables below reflect financial information for the segments and reconciliations to consolidated amounts. As stated in the 2012 Form 10-K, the Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (when applicable). When these items are not applicable, the Company evaluates performance based on net income. There have been no changes in the basis of segmentation nor in the basis of measuring segment profit or loss from those used in the Company’s 2012 Form 10-K. As for segment assets, the significant changes from the segment assets disclosed in the 2012 Form 10-K involve the Exploration and Production, Utility, and Pipeline and Storage segments as well as the All Other category. Total Exploration and Production segment assets, Utility segment assets and Pipeline and Storage segment assets have increased by $98.3 million, $29.9 million, and $29.0 million, respectively, during the three months ended December 31, 2012. The All Other category assets have increased by $16.4 million during the three months ended December 31, 2012.

Quarter Ended December 31, 2012 (Thousands)

	Pipeline	Exploration

	Utility	and Storage	and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$208,563	$43,459	$155,450	$44,166	$451,638	$1,015	$201	$452,854
Intersegment Revenues	$4,311	$22,797	$ -	$426	$27,534	$5,480	$(33,014)	$ -
Segment Profit:								
Net Income (Loss)	$22,878	$16,933	$26,680	$495	$66,986	$1,885	$ (927)	$67,944

Quarter Ended December 31, 2011 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$208,810	$35,225	$135,974	$51,222	$431,231	$937	$255	$432,423
Intersegment Revenues	$4,389	$21,064	$ -	$287	$25,740	$3,362	$(29,102)	$ -
Segment Profit:								
Net Income (Loss)	$19,353	$ 9,959	$30,315	$429	$60,056	$1,404	$(761)	$60,699

Note 8 – Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

Three months ended December 31,

	Retirement Plan		Other Post-Retirement Benefits	
	2012	2011	2012	2011
Service Cost	$ 3,961	$ 3,551	$ 1,176	$ 1,004
Interest Cost	9,124	10,381	4,803	5,329
Expected Return on Plan Assets	(14,336)	(14,925)	(8,218)	(7,243)
Amortization of Prior Service Cost	60	67	(534)	(534)

Amortization of Transition Amount	-	-	2	3
Amortization of Losses	13,194	9,904	5,223	6,014
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [1]	(3,682)	(1,802)	2,703	2,132
	$ 8,321	$ 7,176	$ 5,155	$ 6,705

[1] The Company's policy is to record retirement plan and other post-retirement benefit costs in the Utility segment on a volumetric

basis to reflect the fact that the Utility segment experiences higher throughput of natural gas in the winter months and lower

throughput of natural gas in the summer months.

Employer Contributions. During the three months ended December 31, 2012, the Company contributed $12.2 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $4.3 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2013, the Company expects to contribute between $28.0 million and $32.0 million to the Retirement Plan. Changes in the discount rate, other actuarial assumptions, and asset performance could ultimately cause the Company to fund larger amounts to the Retirement Plan in fiscal 2013 in order to be in compliance with the Pension Protection Act of 2006 (as impacted by the Moving Ahead for Progress in the 21st Century Act). In July 2012, the Surface Transportation Extension Act, which is also referred to as the Moving Ahead for Progress in the 21st Century Act (the Act), was passed by Congress and signed by the President. The Act included pension funding stabilization provisions. The Company is currently in the process of evaluating its future contributions in light of the provisions of the Act. In the remainder of 2013, the Company expects to contribute between $11.0 million and $15.0 million to its VEBA trusts and 401(h) accounts.

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

OVERVIEW

Please note that this overview is a high-level summary of items that are discussed in greater detail in subsequent sections of this report.

The Company is a diversified energy holding company that owns a number of subsidiary operating companies, and reports financial results in four reportable business segments. For the quarter ended December 31, 2012 compared to the quarter ended December 31, 2011, the Company experienced an increase in earnings of $7.2 million. The earnings increase for the quarter is primarily due to higher earnings in the Pipeline and Storage segment and Utility segment, partially offset by lower earnings in the Exploration and Production segment. For further discussion of the Company's earnings, refer to the Results of Operations section below.

The Company's natural gas reserve base has grown substantially in recent years due to its development of reserves in the Marcellus Shale, a Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York. The Company controls the natural gas interests associated with approximately 775,000 net acres within the Marcellus Shale area, with a majority of the interests held in fee, carrying no royalty and no lease expirations. Natural gas proved developed and undeveloped reserves in the Appalachian region increased from 607 Bcf at September 30, 2011 to 925 Bcf at September 30, 2012. The Company has spent significant amounts of capital in this region related to the development of such reserves. For the three months ended December 31, 2012, the Company's Exploration and Production segment had capital expenditures of $109.0 million in the Appalachian region, of which $102.3 million was spent towards the development of the Marcellus Shale. The Company's fiscal 2013 estimated capital expenditures in the Appalachian region are expected to be approximately $425.0 million, up from the previously reported estimated capital expenditures in the Appalachian region of $405.3 million.

The Company's Pipeline and Storage segment has been spending significant amounts to build pipeline gathering and transmission facilities to connect Marcellus Shale production with existing pipelines in the region. One such project, the Northern Access expansion project, began initial service on November 1, 2012, with full service implemented on January 16, 2013. The Northern Access expansion project is discussed further in the Investing Cash Flow section that follows.

From a capital resources perspective, the Company has largely been able to meet its capital expenditure needs for all of the above projects by using cash from operations as well as both short and long-term debt. Going forward, the Company plans to continue its use of short-term debt and expects to issue long-term debt in the near term to replace long-term debt that matures in March 2013 and reduce short-term borrowings.

The well completion technology referred to as hydraulic fracturing used in conjunction with horizontal drilling continues to be debated. In Pennsylvania, where the Company is focusing its Marcellus Shale development efforts, the permitting and regulatory processes seem to strike a balance between the environmental concerns associated with hydraulic fracturing and the benefits of increased natural gas production. Hydraulic fracturing is a well stimulation technique that has been used for many years, and in the Company’s experience, one that the Company believes has little negative impact to the environment. Nonetheless, the potential for increased state or federal regulation of hydraulic fracturing could impact future costs of drilling in the Marcellus Shale and lead to operational delays or restrictions. There is also the risk that drilling could be prohibited on certain acreage that is prospective for the Marcellus Shale. Please refer to the Risk Factors section of the Company’s 2012 Form 10-K for further discussion.

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to "Critical Accounting Estimates" in Item 7 of the Company's 2012 Form 10-K. There have been no material changes to that disclosure other than as set forth below. The information presented below updates and should be read in conjunction with the critical accounting estimates in that Form 10-K.

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Oil and Gas Exploration and Development Costs. The Company, in its Exploration and Production segment, follows the full cost method of accounting for determining the book value of its oil and natural gas properties. In accordance with this methodology, the Company is required to perform a quarterly ceiling test. Under the ceiling test, the present value of future revenues from the Company's oil and gas reserves based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period (the “ceiling”) is compared with the book value of the Company’s oil and gas properties at the balance sheet date. If the book value of the oil and gas properties exceeds the ceiling, a non-cash impairment charge must be recorded to reduce the book value of the oil and gas properties to the calculated ceiling. At December 31, 2012, the ceiling exceeded the book value of the oil and gas properties by approximately $7.3 million. The 12-month average of the first day of the month price for crude oil for each month during the twelve months ended December 31, 2012, based on posted Midway Sunset prices, was $103.05 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during the twelve months ended December 31, 2012, based on the quoted Henry Hub spot price for natural gas, was $2.76 per MMBtu. (Note – Because actual pricing of the Company’s various producing properties varies depending on their location and hedging, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Midway Sunset and Henry Hub prices, which are only indicative of 12-month average prices for the twelve months ended December 31, 2012.) If natural gas average prices used in the ceiling test calculation at December 31, 2012 had been $1 per MMBtu lower, the book value of the Company’s oil and gas properties would have exceeded the ceiling by approximately $219.8 million, which would have resulted in an impairment charge. If crude oil average prices used in the ceiling test calculation at December 31, 2012 had been $5 per Bbl lower, the book value of the Company’s oil and gas properties would have exceeded the ceiling by approximately $38.9 million, which would have resulted in an impairment charge. If both natural gas and crude oil average prices used in the ceiling test calculation at December 31, 2012 were lower by $1 per MMBtu and $5 per Bbl, respectively, the book value of the Company’s oil and gas properties would have exceeded the ceiling by approximately $265.7 million, which would have resulted in an impairment charge. These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation. For a more complete discussion of the full cost method of accounting, refer to "Oil and Gas Exploration and Development Costs" under "Critical Accounting Estimates" in Item 7 of the Company's 2012 Form 10-K.

RESULTS OF OPERATIONS

Earnings

The Company’s earnings were $67.9 million for the quarter ended December 31, 2012 compared with earnings of $60.7 million for the quarter ended December 31, 2011. The increase in earnings of $7.2 million is primarily a result of higher earnings in the Pipeline and Storage segment and Utility segment. Lower earnings in the Exploration and Production segment partially offset these increases.

Additional discussion of earnings in each of the business segments can be found in the business segment information that follows. Note that all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted.

Earnings (Loss) by Segment

Three Months Ended December 31 (Thousands)	2012	2011	Increase (Decrease)
Utility	$ 22,878	$ 19,353	$ 3,525
Pipeline and Storage	16,933	9,959	6,974
Exploration and Production	26,680	30,315	(3,635)
Energy Marketing	495	429	66
Total Reportable Segments	66,986	60,056	6,930
All Other	1,885	1,404	481
Corporate	(927)	(761)	(166)
Total Consolidated	$ 67,944	$ 60,699	$ 7,245

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Utility

Utility Operating Revenues

Three Months Ended December 31 (Thousands)	2012	2011	Increase (Decrease)
Retail Sales Revenues:			
Residential	$ 145,805	$ 148,263	$ (2,458)
Commercial	17,592	17,645	(53)
Industrial	1,773	1,022	751
	165,170	166,930	(1,760)
Transportation	37,253	34,965	2,288
Off-System Sales	8,720	9,145	(425)
Other	1,731	2,159	(428)
	$ 212,874	$ 213,199	$ (325)

Utility Throughput

Three Months Ended December 31 (MMcf)	2012	2011	Increase (Decrease)
Retail Sales:			
Residential	15,153	14,549	604
Commercial	1,967	1,994	(27)
Industrial	301	101	200
	17,421	16,644	777
Transportation	18,637	16,928	1,709
Off-System Sales	2,429	2,745	(316)
	38,487	36,317	2,170

Degree Days

Three Months Ended December 31				Percent Colder (Warmer) Than	
	Normal	2012	2011	Normal[1]	Prior Year[1]
Buffalo	2,253	2,036	1,848	(9.6)	10.2
Erie	2,044	1,898	1,721	(7.1)	10.3

(1) Percents compare actual 2012 degree days to normal degree days and actual 2012 degree days to actual 2011 degree days.

2012 Compared with 2011

Operating revenues for the Utility segment decreased $0.3 million for the quarter ended December 31, 2012 as compared with the quarter ended December 31, 2011. This decrease resulted from a $1.8 million decrease in retail gas sales revenues, a $0.4 million decrease in off-system sales revenue (due to lower volumes), and a $0.4 million decrease in other revenue (largely due to lower capacity release revenues). These were partially offset by a $2.3 million increase in transportation revenue. The decrease in retail gas sales revenues was primarily due to the recovery of lower gas costs (subject to certain timing variations, gas costs are recovered dollar for dollar in revenues) and was partially offset by the impact of a 0.8 Bcf increase in throughput (the result of colder weather, which more than offset the impact of migration of customers from retail sales to transportation services). The recovery of lower gas costs resulted from a lower cost of purchased gas. The Utility segment's average cost of purchased gas, including the cost of transportation and storage, was $5.37 per Mcf for the three months ended December 31, 2012, a decrease of 7.1% from the average cost of $5.78 per Mcf for the three months ended December 31, 2011. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there is not a material impact to margins. The increase in transportation revenues of $2.3 million was primarily due to a

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1.7 Bcf increase in transportation throughput, largely the result of colder weather and the migration of customers from retail sales to transportation services.

The Utility segment's earnings for the quarter ended December 31, 2012 were $22.9 million, an increase of $3.5 million when compared with earnings of $19.4 million for the quarter ended December 31, 2011. The increase in earnings is due to lower operating expenses ($1.3 million), colder weather ($1.4 million) and lower income tax expense ($0.5 million). The decrease in operating expenses was due to lower personnel costs.

The impact of weather variations on earnings in the Utility segment's New York rate jurisdiction is mitigated by that jurisdiction's weather normalization clause (WNC). The WNC in New York, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the Utility segment's New York customers. For the quarter ended December 31, 2012, the WNC preserved earnings of approximately $0.6 million, as the weather was warmer than normal. For the quarter ended December 31, 2011, the WNC preserved earnings of approximately $1.4 million, as the weather was warmer than normal.

Pipeline and Storage

Pipeline and Storage Operating Revenues

Three Months Ended December 31 (Thousands)	2012	2011	Increase
Firm Transportation	$ 46,597	$ 39,132	$ 7,465
Interruptible Transportation	501	402	99
	47,098	39,534	7,564
Firm Storage Service	17,436	16,498	938
Other	1,722	257	1,465
	$ 66,256	$ 56,289	$ 9,967

Pipeline and Storage Throughput

Three Months Ended December 31 (MMcf)	2012	2011	Increase
Firm Transportation	123,413	83,608	39,805
Interruptible Transportation	1,252	808	444
	124,665	84,416	40,249

2012 Compared with 2011

Operating revenues for the Pipeline and Storage segment increased $10.0 million in the quarter ended December 31, 2012 as compared with the quarter ended December 31, 2011. The increase was primarily due to an increase in transportation revenues of $7.6 million and an increase in storage revenues of $0.9 million. The increase in transportation revenues was largely due to demand charges on new contracts for transportation service on Supply Corporation's Line N 2012 Expansion Project, which was placed fully in service in November 2012, Supply Corporation's Northern Access expansion project, which was partially placed in service in November 2012 and Empire's Tioga County Extension Project, which was placed in service in November 2011. These projects provide pipeline capacity for Marcellus Shale production. The Line N 2012 Expansion Project and the Northern Access expansion project are discussed in the Investing Cash Flow section that follows. Additionally, effective May 2012, both transportation and storage revenues increased due to an overall net increase in tariff rates as a result of the implementation of Supply Corporation's rate case settlement which was approved by FERC on August 6, 2012. In addition to these increases, there was an increase in cashout revenues of $0.8 million (reported as a part of other revenue in the table above). Cashout revenues are completely offset by purchased gas expense and as a result have no impact on earnings. A gain of $0.6 million resulting from the sale of efficiency gas inventory (i.e., shipper-supplied gas retained in excess of operational needs) during the quarter ended December 31, 2012 also contributed to the increase in other revenue as shown in the table above. This gain related to the sale of efficiency gas retained as inventory prior to May 1, 2012. In accordance with Supply Corporation's rate case settlement, shipper-supplied gas retained subsequent to May 1, 2012 is subject to a tracking mechanism that

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will adjust fuel retention rates annually to reflect actual experience, thus eliminating any future revenue and earnings impact to Supply Corporation.

Transportation volumes for the quarter ended December 31, 2012 increased by 40.2 Bcf from the prior year's quarter. The large increase in transportation volumes for the quarter primarily reflects the impact of the above mentioned expansion projects being placed in service. Volume fluctuations generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

The Pipeline and Storage segment's earnings for the quarter ended December 31, 2012 were $16.9 million, an increase of $6.9 million when compared with earnings of $10.0 million for the quarter ended December 31, 2011. The increase in earnings is primarily due to the earnings impact of higher transportation and storage revenues of $5.5 million and the earnings impact associated with the sale of efficiency gas inventory ($0.4 million), as discussed above, combined with a decrease in depreciation expense ($1.0 million) and an increase in the allowance for funds used during construction (equity component) of $0.3 million. The decrease in depreciation expense primarily reflects a decrease in depreciation rates as specified in Supply Corporation's rate case settlement offset slightly by incremental depreciation expense related to the projects that were placed in service within the last year. The increase in the allowance for funds used during construction is mainly due to construction during the quarter ended December 31, 2012 on Supply Corporation's Northern Access and Line N 2012 expansion projects.

Exploration and Production

Exploration and Production Operating Revenues

Three Months Ended December 31 (Thousands)	2012	2011	Increase (Decrease)
Gas (after Hedging)	$ 82,774	$ 66,512	$ 16,262
Oil (after Hedging)	69,034	65,671	3,363
Gas Processing Plant	6,042	6,961	(919)
Other	599	(31)	630
Intrasegment Elimination [(1)]	(2,999)	(3,139)	140
	$ 155,450	$ 135,974	$ 19,476

(1) Represents the elimination of certain West Coast gas production revenue included in “Gas (after Hedging)” in the table above that was sold to the gas processing plant shown in the table above. An elimination for the same dollar amount was made to reduce the gas processing plant’s Purchased Gas expense.

Production Volumes

			Increase
Three Months Ended December 31	2012	2011	(Decrease)
Gas Production (MMcf)			
Appalachia	19,496	13,111	6,385
West Coast	745	817	(72)
Total Production	20,241	13,928	6,313
Oil Production (Mbbl)			
Appalachia	6	10	(4)
West Coast	708	709	(1)
Total Production	714	719	(5)

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Average Prices

	2012	2011	Increase (Decrease)
Average Gas Price/Mcf			
Appalachia	$ 3.35	$ 3.39	$ (0.04)
West Coast	$ 3.77	$ 4.95	$ (1.18)
Weighted Average	$ 3.36	$ 3.48	$ (0.12)
Weighted Average After Hedging	$ 4.09	$ 4.78	$ (0.69)
Average Oil Price/Bbl			
Appalachia	$ 87.83	$ 88.16	$ (0.33)
West Coast	$ 100.10	$ 109.23	$ (9.13)
Weighted Average	$ 100.01	$ 108.93	$ (8.92)
Weighted Average After Hedging	$ 96.69	$ 91.38	$ 5.31

2012 Compared with 2011

Operating revenues for the Exploration and Production segment increased $19.5 million for the quarter ended December 31, 2012 as compared with the quarter ended December 31, 2011. Gas production revenue after hedging increased $16.3 million, due to an increase in production which was partially offset by a $0.69 per Mcf decrease in the weighted average price of natural gas after hedging. The increase in Appalachian production was primarily due to increased development within the Marcellus Shale formation, mainly in Lycoming County, Pennsylvania with additional Marcellus Shale production from Tioga County, Pennsylvania. Oil production revenue after hedging increased $3.4 million, due to a $5.31 per Bbl increase in the weighted average price of crude oil after hedging as production was flat quarter over quarter.

The Exploration and Production segment's earnings for the quarter ended December 31, 2012 were $26.7 million, a decrease of $3.6 million when compared with earnings of $30.3 million for the quarter ended December 31, 2011. Higher natural gas production and higher realized crude oil prices (after hedging) increased earnings by $19.6 million

and $2.5 million, respectively. However, these items were more than offset by lower natural gas prices after hedging ($9.0 million), higher depletion expense ($6.8 million), higher lease operating expenses ($4.6 million), higher general, administrative and other operating expenses ($3.0 million), higher interest expense ($2.2 million), and lower crude oil production ($0.3 million). The increase in depletion expense is primarily due to an increase in the depletable base (due to increased capital spending in the Appalachian region within the last few years) and higher production. The increase in lease operating expense is largely attributable to higher transportation, compression, and water disposal costs in the Appalachian region coupled with higher well repair, maintenance, and labor costs in the West Coast region. The increase in general, administrative and other operating expenses was largely due to the termination of a lease for a drilling rig as part of the Company's overall plan to reduce future Appalachian capital expenditures in light of lower natural gas prices. The increase in interest expense was attributable to an increase in the weighted average amount of debt (due to the Exploration and Production segment's share ($470 million) of the $500 million long-term debt issuance in December 2011).

Energy Marketing

Energy Marketing Operating Revenues

Three Months Ended December 31 (Thousands)	2012	2011	Increase (Decrease)
Natural Gas (after Hedging)	$ 44,572	$ 51,498	$ (6,926)
Other	20	11	9
	$ 44,592	$ 51,509	$ (6,917)

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Energy Marketing Volume

Three Months Ended December 31	2012	2011	Increase
Natural Gas – (MMcf)	10,365	10,312	53

2012 Compared with 2011

Operating revenues for the Energy Marketing segment decreased $6.9 million for the quarter ended December 31, 2012 as compared with the quarter ended December 31, 2011. The decrease reflects a decline in gas sales revenue due to a lower average price of natural gas.

The Energy Marketing segment's earnings for the quarter ended December 31, 2012 were $0.5 million, an increase of $0.1 million when compared with earnings of $0.4 million for the quarter ended December 31, 2011. The increase was primarily due to lower operating costs of $0.1 million. Margin was essentially unchanged from the quarter ended December 31, 2011.

Corporate and All Other

2012 Compared with 2011

Corporate and All Other operations recorded earnings of $1.0 million for the quarter ended December 31, 2012, an increase of $0.4 million when compared with earnings of $0.6 million for the quarter ended December 31, 2011. The increase in earnings was primarily due to higher gathering and processing revenues of $1.4 million and was partially offset by higher depreciation expense of $0.6 million (due to an increase in Midstream Corporation's gathering plant balances). The increase in gathering and processing revenues are due to Midstream Corporation's increase in gathering operations for Marcellus Shale gas in the Pennsylvania counties of Tioga and Lycoming.

Interest Expense on Long-Term Debt (amounts below are pre-tax amounts)

Interest on long-term debt increased $2.8 million for the quarter ended December 31, 2012 as compared with the quarter ended December 31, 2011. This increase is due to increased borrowings. The Company issued $500 million of notes at 4.90% in December 2011 and repaid $150 million of 6.70% notes that matured in November 2011.

CAPITAL RESOURCES AND LIQUIDITY

The Company's primary sources of cash during the three-month period ended December 31, 2012 consisted of cash provided by operating activities, net proceeds from short-term borrowings and net proceeds from the issuance of common stock. The Company's primary sources of cash during the three-month period ended December 31, 2011 consisted of proceeds from the issuance of long-term debt and cash provided by operating activities. During the three months ended December 31, 2012 and December 31, 2011, the common stock used to fulfill the requirements of the Company's 401(k) plans was obtained via open market purchases. In April 2011, the Company began issuing original issue shares for the Direct Stock Purchase and Dividend Reinvestment Plan.

Operating Cash Flow

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization and deferred income taxes.

Cash provided by operating activities in the Utility and Pipeline and Storage segments may vary substantially from period to period because of the impact of rate cases. In the Utility segment, supplier refunds, over- or under-recovered purchased gas costs and weather may also significantly impact cash flow. The impact of weather on cash flow is tempered in the Utility segment's New York rate jurisdiction by its

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WNC and in the Pipeline and Storage segment by the straight fixed-variable rate design used by Supply Corporation and Empire.

Because of the seasonal nature of the heating business in the Utility and Energy Marketing segments, revenues in these segments are relatively high during the heating season, primarily the first and second quarters of the fiscal year, and receivable balances historically increase during these periods from the receivable balances at September 30.

The storage gas inventory normally declines during the first and second quarters of the fiscal year and is replenished during the third and fourth quarters. For storage gas inventory accounted for under the LIFO method, the current cost of replacing gas withdrawn from storage is recorded in the Consolidated Statements of Income and a reserve for gas replacement is recorded in the Consolidated Balance Sheets under the caption "Other Accruals and Current Liabilities." Such reserve is reduced as the inventory is replenished.

Cash provided by operating activities in the Exploration and Production segment may vary from period to period as a result of changes in the commodity prices of natural gas and crude oil as well as changes in production. The Company uses various derivative financial instruments, including price swap agreements and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $146.0 million for the three months ended December 31, 2012, an increase of $50.3 million compared with $95.7 million provided by operating activities for the three months ended December 31, 2011. The increase in cash provided by operating activities is primarily due to an increase in cash provided by operations in both the Utility segment and Pipeline and Storage segment. The increase in the Utility segment can be attributed to the timing of gas cost recovery. The increase in the Pipeline and Storage segment is due to higher cash receipts from higher transportation revenues as a result of expansion projects coming on-line and higher tariff rates from the implementation of Supply Corporation’s rate case proceeding, as discussed above.

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company’s expenditures for long-lived assets totaled $181.6 million during the three months ended December 31, 2012 and $279.0 million for the three months ended December 31, 2011. These amounts include accounts payable and accrued liabilities related to capital expenditures and will differ from capital expenditures shown on the Consolidated Statement of Cash Flows. They are included in subsequent Consolidated Statement of Cash Flows when they are paid. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets

Three Months Ended December 31,			Increase
(Millions)	2012	2011	(Decrease)
Utility :			
Capital Expenditures	$14.4 (1)	$11.3 (2)	$ 3.1
Pipeline and Storage:			
Capital Expenditures	25.7 (1)	44.2 (2)	(18.5)
Exploration and Production:			
Capital Expenditures	127.7 (1)	191.9 (2)	(64.2)
All Other:			
Capital Expenditures	13.8 (1)	31.6 (2)	(17.8)
	$181.6	$ 279.0	$ (97.4)

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(1) At December 31, 2012, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Utility segment and the All Other category include $73.4 million, $10.5 million, $0.1 million and $2.1 million, respectively, of accounts payable and accrued liabilities related to capital expenditures. At September 30, 2012, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Utility segment and the All Other category included $38.9 million, $12.7 million, $3.2 million and $12.7 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

(2) At December 31, 2011, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Utility segment and the All Other category included $123.1 million, $16.6 million, $0.4 million and $14.9 million, respectively, of accounts payable and accrued liabilities related to capital expenditures. At September 30, 2011, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Utility segment and the All Other category included $103.3 million, $16.4 million, $2.3 million and $3.1 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

Utility

The majority of the Utility capital expenditures for the three months ended December 31, 2012 and December 31, 2011 were made for replacement of mains and main extensions, as well as for the replacement of service lines.

Pipeline and Storage

The majority of the Pipeline and Storage capital expenditures for the three months ended December 31, 2012 were related to the construction of Supply Corporation's Northern Access expansion project ($14.4 million) and Supply Corporation's Line N 2012 Expansion Project ($3.7 million) as discussed below. The majority of the Pipeline and Storage capital expenditures for the three months ended December 31, 2011 were related to the construction of Empire's Tioga County Extension Project ($17.4 million), Supply Corporation's Line N 2012 Expansion Project ($6.6 million), and Supply Corporation's Northern Access expansion project ($2.5 million). The Pipeline and Storage capital expenditures for the three months ended December 31, 2012 and December 31, 2011 also include additions, improvements, and replacements to this segment's transmission and gas storage systems.

In light of the growing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia — specifically in the Marcellus and Utica Shale producing areas — Supply Corporation and Empire are actively pursuing several expansion projects and paying for preliminary survey and investigation costs, which are initially recorded as Deferred Charges on the Consolidated Balance Sheet. An offsetting reserve is established as those preliminary survey and investigation costs are incurred, which reduces the Deferred Charges balance and increases Operation and Maintenance Expense on the Consolidated Statement of Income. The Company reviews all projects on a quarterly basis, and if it is determined that it is highly probable that the project will be built, the reserve is reversed. This

reversal reduces Operation and Maintenance Expense and reestablishes the original balance in Deferred Charges. After the reversal of the reserve, the amounts remain in Deferred Charges until such time as capital expenditures for the project have been incurred and activities that are necessary to get the construction project ready for its intended use are in progress. At that point, the balance is transferred from Deferred Charges to Construction Work in Progress, a component of Property, Plant and Equipment on the Consolidated Balance Sheet. As of December 31, 2012, the total amount reserved for the Pipeline and Storage segment's preliminary survey and investigation costs was $6.8 million.

Supply Corporation and Empire are moving forward with several projects designed to move anticipated Marcellus and Utica production gas to other interstate pipelines and to markets beyond the Supply Corporation and Empire pipeline systems. Projects where the Company has begun to make significant investments of preliminary survey and investigation costs and/or where shipper agreements have been executed are described below.

Supply Corporation has begun service under a transportation service agreement with Statoil Natural Gas LLC ("Statoil") which provides 320,000 Dth/day of firm transportation capacity for a 20-year term in conjunction with Supply Corporation's "Northern Access" expansion project. This capacity provides Statoil with a firm transportation path from the Tennessee Gas Pipeline ("TGP") 300 Line at Ellisburg and Transcontinental Pipeline at Leidy to the TransCanada Pipeline at Niagara. These receipt points are attractive because they provide routes for Marcellus shale gas from the TGP 300 Line and Transco Leidy Line in northern Pennsylvania, to be transported from the Marcellus supply basin to northern markets. Supply Corporation received from the FERC its NGA Section 7(c) Certificate authorization of this project on October 20, 2011, and received its Notice to Proceed on April 13, 2012. The project facilities involve

approximately 9,500 horsepower of additional compression at Supply Corporation's existing Ellisburg Station and a new approximately 5,000 horsepower compressor station in Wales, New York, along with other system enhancements including enhancements to the jointly owned Niagara Spur Loop Line. Initial service began on November 1, 2012, with full service implemented on January 16, 2013. The cost estimate for the Northern Access expansion is $77.3 million. As of December 31, 2012, approximately $68.3 million has been spent on the Northern Access expansion project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2012.

Supply Corporation has also begun service under three service agreements for a total of 163,000 Dth/day of additional capacity on Line N to TETCO at Holbrook ("Line N 2012 Expansion Project"). The FERC issued the NGA Section 7(c) Certificate on March 29, 2012 for authorizing construction and operation of the Line N 2012 Expansion Project which consists of an additional 20,620 horsepower of compression at its Buffalo Compressor Station, and the replacement of 4.85 miles of 20" pipe with 24" pipe, to enhance the integrity and reliability of its system and to create the additional capacity. On October 3, 2012, Supply Corporation put in service a portion of the Project facilities, began early interim service for Range Resources, and began full service for all Project shippers on November 1, 2012. The cost estimate for the Line N 2012 Expansion Project is approximately $33.4 million for the incremental capacity plus approximately $7.8 million allocated to system replacement. Of this amount, approximately $36.6 million has been spent on the Line N 2012 Expansion Project through December 31, 2012, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2012.

On August 4, 2011, Supply Corporation concluded an Open Season to increase its capability to move gas north on its Line N system and deliver gas to Tennessee Gas Pipeline at Mercer, Pennsylvania, a pooling point recently established at Tennessee's Station 219 ("Mercer Expansion Project"). Supply Corporation has executed a precedent agreement for 105,000 Dth/day, all of the project capacity, for service expected to begin November 2014. The preliminary cost estimate is $20 million. Supply Corporation expects to construct the required approximately 3,600 horsepower of compression at Mercer under its FERC blanket certificate authorization. As of December 31, 2012, less than $0.1 million has been spent to study the Mercer Expansion Project, all of which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2012.

On April 11, 2012, Supply Corporation concluded an Open Season to increase its capacity to move gas south on its Line N system to TETCO at Holbrook ("Line N 2013 Project"). Supply Corporation has executed a precedent agreement for 30,000 Dth/day, all of the project capacity, for service expected to begin November 2013. The preliminary cost estimate is $4.3 million. Supply Corporation expects to construct the required 1.25 miles of 24" pipeline extension under its FERC blanket certificate authorization. As of December 31, 2012, approximately $0.1 million has been spent to study the Line N 2013 Project, all of which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2012.

On December 17, 2010, Empire concluded an Open Season for up to 260,000 Dth/day of additional capacity from Tioga County, Pennsylvania, to TransCanada Pipeline and the TGP 200 Line, as well as additional short-haul capacity to Millennium Pipeline at Corning ("Central Tioga County Extension"). Empire is in discussions with an anchor shipper for a significant portion of the proposed capacity, with service commencing in late 2015, likely tied to a rebound in

commodity pricing due to the dry gas nature of this area of the Marcellus. The Central Tioga County Extension project may involve up to 25,000 horsepower of compression at up to three new stations and a 25 mile 24” pipeline extension, at a preliminary cost estimate of $150 million. As of December 31, 2012, approximately $0.2 million has been spent to study the Central Tioga County Extension project, which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2012.

Exploration and Production

The Exploration and Production segment capital expenditures for the three months ended December 31, 2012 were primarily well drilling and completion expenditures and included approximately $109.0 million for the Appalachian region (including $102.3 million in the Marcellus Shale area) and $18.7 million for the West Coast region. These amounts included approximately $53.6 million spent to develop proved undeveloped reserves.

The Exploration and Production segment capital expenditures for the three months ended December 31, 2011 were primarily well drilling and completion expenditures and included approximately $181.2 million for the Appalachian region (including $172.0 million in the Marcellus Shale area) and $10.7 million for the West Coast region. These amounts included approximately $55.7 million spent to develop proved undeveloped reserves.

For all of fiscal 2013, the Company expects to spend $520.0 million on Exploration and Production segment capital expenditures. Previously reported 2013 estimated capital expenditures for the Exploration and Production segment were $485.0 million. In the Appalachian region, estimated capital expenditures will increase from $405.3 million to $425.0 million. Estimated capital expenditures in the West Coast region will increase from $79.7 million to $95.0 million.

All Other

The majority of the All Other category's capital expenditures for the three months ended December 31, 2012 and December 31, 2011 were for the construction of Midstream Corporation's Trout Run Gathering System, as discussed below.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Corporation, is developing a gathering system in Lycoming County, Pennsylvania. The project, Trout Run Gathering System, was placed in service in May 2012. The current system consists of approximately 27 miles of backbone and in-field gathering system. The complete buildout is expected to include additional in-field gathering pipelines and compression at a total cost of approximately $185 million. As of December 31, 2012, the Company has spent approximately $94.4 million in costs related to this project, including approximately $14.3 million spent during the three months ended December 31, 2012, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2012.

NFG Midstream Covington, LLC, a wholly owned subsidiary of Midstream Corporation, has been expanding its gathering system in Tioga County, Pennsylvania. As of December 31, 2012, the Company has spent approximately $26.7 million in costs related to the Covington Gathering System. All costs associated with this gathering system are included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2012.

In addition, two other wholly owned subsidiaries of Midstream Corporation, NFG Midstream Mt. Jewett, LLC and NFG Midstream Tionesta, LLC are constructing gathering pipelines and interconnects to TGP. As of December 31, 2012, approximately $2.9 million has been spent on the NFG Midstream Mt. Jewett gathering system and approximately $0.7 million has been spent on the NFG Midstream Tionesta gathering system, all of which has been

capitalized as Construction Work in Progress.

Midstream Corporation is planning the construction of several smaller gathering systems. As of December 31, 2012, the Company has spent approximately $0.5 million in costs related to these projects, all of which has been capitalized as Construction Work in Progress.

Project Funding

The Company has been financing the Pipeline and Storage segment projects and the Midstream Corporation projects mentioned above, as well as the Exploration and Production segment capital expenditures, with cash from operations and both short and long-term borrowings. Going forward, while the Company expects to use cash from operations as the first means of financing these projects, it is expected that the Company will continue to use a combination of both short and long-term borrowings during fiscal 2013, as well as the issuance of additional long-term debt in the near term. The level of such short-term borrowings will depend upon the amounts of cash provided by operations, which, in turn, will likely be impacted by natural gas and crude oil prices combined with production from existing wells.

The Company continuously evaluates capital expenditures and potential investments in corporations, partnerships, and other business entities. The amounts are subject to modification for opportunities such as the acquisition of attractive oil and gas properties, natural gas storage facilities and the

expansion of natural gas transmission line capacities. While the majority of capital expenditures in the Utility segment are necessitated by the continued need for replacement and upgrading of mains and service lines, the magnitude of future capital expenditures or other investments in the Company's other business segments depends, to a large degree, upon market conditions.

Financing Cash Flow

Consolidated short-term debt increased $67.0 million when comparing the balance sheet at December 31, 2012 to the balance sheet at September 30, 2012. The maximum amount of short-term debt outstanding during the three months ended December 31, 2012 was $254.6 million. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, repurchases of stock, other working capital needs and repayment of long-term debt. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. At December 31, 2012, the Company had outstanding commercial paper and short-term notes payable to banks of $220.0 and $18.0 million, respectively.

As for bank loans, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which totaled $335.0 million at December 31, 2012, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed at amounts near current levels, or substantially replaced by similar lines.

The total amount available to be issued under the Company's commercial paper program is $300.0 million. At December 31, 2012, the commercial paper program was backed by a syndicated committed credit facility totaling $750.0 million, which commitment extends through January 6, 2017. Under the committed credit facility, the Company agreed that its debt to capitalization ratio would not exceed .65 at the last day of any fiscal quarter through January 6, 2017. At December 31, 2012, the Company's debt to capitalization ratio (as calculated under the facility) was .45. The constraints specified in the committed credit facility would have permitted an additional $2.10 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.

If a downgrade in any of the Company's credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its committed credit facility, uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.

Under the Company's existing indenture covenants, at December 31, 2012, the Company would have been permitted to issue up to a maximum of $1.60 billion in additional long-term unsecured indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace maturing debt. The Company's present liquidity position is believed to be adequate to satisfy known demands. However, if the Company were to experience a significant loss in the future (for example, as a result of an impairment of oil and gas properties), it is possible, depending on factors including the magnitude of the loss, that these indenture covenants would restrict the Company's ability to issue additional long-term unsecured indebtedness for a period of up to nine calendar months, beginning with the fourth calendar month following the loss. This would not at any time preclude the Company from issuing new indebtedness to replace maturing debt.

The Company's 1974 indenture pursuant to which $99.0 million (or 7.1%) of the Company's long-term debt (as of December 31, 2012) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement, or (ii) to perform any other term in any other such indenture or agreement, and the effect of the

failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company’s $750.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more, or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of December 31, 2012, the Company did not have any debt outstanding under the committed credit facility.

The Company’s embedded cost of long-term debt was 6.17% at both December 31, 2012 and December 31, 2011.

Current Portion of Long-Term Debt at December 31, 2012 consists of $250.0 million of 5.25% notes that mature in March 2013. The Company expects to issue long-term debt in the near term to replace the long-term debt that matures in March 2013.

On December 1, 2011, the Company issued $500.0 million of 4.90% notes due December 1, 2021. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $496.1 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used for general corporate purposes, including refinancing short-term debt that was used to pay the $150 million due at the maturity of the Company’s 6.70% notes in November 2011.

The Company may issue debt or equity securities in a public offering or a private placement from time to time. The amounts and timing of the issuance and sale of debt or equity securities will depend on market conditions, indenture requirements, regulatory authorizations and the capital requirements of the Company.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating leases. The Company’s consolidated subsidiaries have operating leases, the majority of which are with the Exploration and Production segment and Corporate operations, having a remaining lease commitment of

approximately $77.2 million. These leases have been entered into for the use of compressors, drilling rigs, buildings, meters and other items and are accounted for as operating leases. The operating lease commitment at December 31, 2012 is substantially lower than the operating lease commitment of $108.9 million at September 30, 2012. As discussed above in Results of Operations, the Exploration and Production segment terminated a lease agreement for one of its drilling rigs during the quarter ended December 31, 2012. This termination reduced the Company's future operating lease obligations from what was disclosed in the 2012 Form 10-K by $6.8 million for 2013, $9.1 million for 2014 and $7.3 million for 2015.

OTHER MATTERS

In addition to the legal proceedings disclosed in Part II, Item 1 of this report, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the quarterly and annual period in which they are resolved, they are not expected to change materially the Company's

present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

During the three months ended December 31, 2012, the Company contributed $12.2 million to its Retirement Plan and $4.3 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2013, the Company expects to contribute between $28.0 million and $32.0 million to the Retirement Plan. Changes in the discount rate, other actuarial assumptions, and asset performance could ultimately cause the Company to fund larger amounts to the Retirement Plan in fiscal 2013 in order to be in compliance with the Pension Protection Act of 2006. In July 2012, the Surface Transportation Extension Act, which is also referred to as the Moving Ahead for Progress in the 21st Century Act (the Act), was passed by Congress and signed by the President. The Act included pension funding stabilization provisions. The Company is currently in the process of evaluating its future contributions in light of the provisions of the Act. In the remainder of 2013, the Company expects to contribute between $11.0 million and $15.0 million to its VEBA trusts and 401(h) accounts.

Market Risk Sensitive Instruments

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions related to the swaps and over-the-counter derivatives markets. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives have or will become effective as federal agencies (including the CFTC, various banking regulators and the SEC) adopt rules to implement the law. For purposes of the Dodd-Frank Act, under rules adopted by the SEC and/or CFTC, the Company believes that it qualifies as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge or mitigate commercial risk. Nevertheless, other rules that are being developed could have a significant impact on the Company. For example, banking regulators have proposed a rule that would require swap dealers and major swap participants subject to their jurisdiction to collect initial and variation margin from counterparties that are non-financial end users, though such swap dealers and major swap participants would have the discretion to set thresholds for posting margin (unsecured credit limits). Regardless of the levels of margin that might be required, concern remains that swap dealers and major swap participants will pass along their increased capital and margin costs through higher prices and reductions in thresholds for posting margin. In addition, while the Company expects to be exempt from the Dodd-Frank Act’s requirement that swaps be cleared and traded on exchanges or swap execution facilities, the cost of entering into a non-exchange cleared swap that is available as an exchange cleared swap may be greater. The Company continues to monitor these developments but cannot predict the impact the Dodd-Frank Act may ultimately have on its operations.

In accordance with the authoritative guidance for fair value measurements, the Company has identified certain inputs used to recognize fair value as Level 3 (unobservable inputs). The Level 3 derivative net liabilities relate to crude oil swap agreements used to hedge forecasted sales at a specific location (southern California). The Company’s internal model that is used to calculate fair value applies a historical basis differential (between the sales locations and NYMEX) to a forward NYMEX curve because there is not a forward curve specific to this sales location. Given the high level of historical correlation between NYMEX prices and prices at this sales location, the Company does not believe that the fair value recorded by the Company would be significantly different from what it expects to receive

upon settlement.

The Company uses the crude oil swaps classified as Level 3 to hedge against the risk of declining commodity prices and not as speculative investments. Gains or losses related to these Level 3 derivative net liabilities (including any reduction for credit risk) are deferred until the hedged commodity transaction occurs in accordance with the provisions of the existing guidance for derivative instruments and hedging activities. The Level 3 derivative Net Liabilities amount to $14.1 million at December 31, 2012 and represent 15.5% of the Total Net Assets shown in Part I, Item 1 at Note 2 – Fair Value Measurements at December 31, 2012.

The decrease in the net fair value liability of the Level 3 positions from October 1, 2012 to December 31, 2012, as shown in Part I, Item 1 at Note 2, was attributable to a decrease in the commodity price of crude oil relative to the swap price during that period. The Company believes that these fair values reasonably represent the amounts that the Company would realize upon settlement based on commodity prices that were present at December 31, 2012.

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The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At December 31, 2012, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty (for an asset) or the Company’s (for a liability) credit default swaps rates.

For a complete discussion of market risk sensitive instruments, refer to "Market Risk Sensitive Instruments" in Item 7 of the Company's 2012 Form 10-K. There have been no subsequent material changes to the Company’s exposure to market risk sensitive instruments.

Rate and Regulatory Matters

Utility Operation

Delivery rates for both the New York and Pennsylvania divisions are regulated by the states’ respective public utility commissions and are changed only when approved through a procedure known as a “rate case.” Currently neither division has a rate case on file. In both jurisdictions, delivery rates do not reflect the recovery of purchased gas costs. Prudently-incurred gas costs are recovered through operation of automatic adjustment clauses, and are collected primarily through a separately-stated “supply charge” on the customer bill.

New York Jurisdiction

Customer delivery rates charged by Distribution Corporation’s New York division were established in a rate order issued on December 21, 2007 by the NYPSC. In connection with an efficiency and conservation program, the rate order approved a revenue decoupling mechanism. The revenue decoupling mechanism “decouples” revenues from throughput by enabling the Company to collect from small volume customers its allowed margin on average weather normalized usage per customer. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation.

Pennsylvania Jurisdiction

Distribution Corporation’s current delivery charges in its Pennsylvania jurisdiction were approved by the PaPUC on November 30, 2006 as part of a settlement agreement that became effective January 1, 2007.

Pipeline and Storage

Supply Corporation currently does not have a rate case on file with the FERC. A rate settlement approved by the FERC on August 6, 2012 requires Supply Corporation to make a general rate filing no later than January 1, 2016. In addition, Supply Corporation is not barred from filing a general rate case before such date or at any time.

Empire also has no rate case currently on file with the FERC, but is not subject to any requirement to make any future general rate filing. Empire is also not barred from filing a general rate case at any time.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory policies and procedures. It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs.

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The Company has agreed with the NYDEC to remediate a former manufactured gas plant site located in New York. In February 2009, the Company received approval from the NYDEC of a Remedial Design Work Plan (RDWP) for this site. In October 2010, the Company submitted a RDWP addendum to conduct additional Preliminary Design Investigation field activities necessary to design a successful remediation. An estimated minimum liability for remediation of this site of $14.0 million has been recorded.

At December 31, 2012, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites (including the former manufactured gas plant site discussed above) will be in the range of $16.3 million to $21.9 million. The minimum estimated liability of $16.3 million, which includes the $14.0 million discussed above, has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at December 31, 2012. The Company expects to recover its environmental clean-up costs through rate recovery.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. In the United States, these efforts include legislative proposals and EPA regulations at the federal level, actions at the state level, and private party litigation related to greenhouse gas emissions. While the U.S. Congress has from time to time considered legislation aimed at reducing emissions of greenhouse gases, Congress has not yet passed any federal climate change legislation and we cannot predict when or if Congress will pass such legislation and in what form. In the absence of such legislation, the EPA is regulating greenhouse gas emissions pursuant to the authority granted to it by the federal Clean Air Act. For example, in April 2012, the EPA adopted rules which will restrict emissions associated with oil and natural gas drilling. Compliance with these new rules will not materially change the Company’s ongoing emissions–limiting technologies and practices, and is not expected to have a significant impact on the Company. In addition, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. Legislation or regulation that restricts carbon emissions could increase the Company’s cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. International, federal, state or regional climate change and greenhouse gas measures could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Climate change and greenhouse gas initiatives, and incentives to conserve energy or use alternative energy sources, could also reduce demand for oil and natural gas. But legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

The Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental regulations, new information or other factors could adversely impact the Company.

New Authoritative Accounting and Financial Reporting Guidance

In June 2011, the FASB issued authoritative guidance regarding the presentation of comprehensive income. The new guidance allows companies only two choices for presenting net income and other comprehensive income: in a single continuous statement, or in two separate, but consecutive, statements. The guidance eliminates the option to report other comprehensive income and its components in the statement of changes in equity. This authoritative guidance became effective for the quarter ended December 31, 2012. The Company has updated its financial statements to reflect the new guidance.

In December 2011, the FASB issued authoritative guidance requiring enhanced disclosures regarding offsetting assets and liabilities. Companies are required to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2014 and is not expected to have a significant impact on the Company's financial statements.

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Safe Harbor for Forward-Looking Statements

The Company is including the following cautionary statement in this Form 10-Q to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, estimates of oil and gas quantities, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," ' "seeks," "will," "may," and similar expressions, are "forward-looking statements" as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, but there can be no assurance that management's expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors and matters discussed elsewhere herein, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements:

1. Factors affecting the Company's ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations;

2. Changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing;

3. Changes in the price of natural gas or oil;

4. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;

5. Uncertainty of oil and gas reserve estimates;

6. Significant differences between the Company's projected and actual production levels for natural gas or oil;

7. Changes in demographic patterns and weather conditions;

8. Changes in the availability, price or accounting treatment of derivative financial instruments;

9. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, allowed rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;

10. Delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators;

11. Financial and economic conditions, including the availability of credit, and occurrences affecting the Company's ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company's credit ratings and changes in interest rates and other capital market conditions;

12. Changes in economic conditions, including global, national or regional recessions, and their effect on the demand for, and customers' ability to pay for, the Company's products and services;

13. The creditworthiness or performance of the Company's key suppliers, customers and counterparties;

14. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation;

15. Changes in price differential between similar quantities of natural gas at different geographic locations, and the effect of such changes on the demand for pipeline transportation capacity to or from such locations;

16. Other changes in price differentials between similar quantities of oil or natural gas having different quality, heating value, geographic location or delivery date;

17. Significant differences between the Company's projected and actual capital expenditures and operating expenses;

18. Changes in laws, actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company's pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities;

19. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;

20. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; or

21. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Refer to the "Market Risk Sensitive Instruments" section in Item 2 – MD&A.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that

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evaluation, the Company's Chief Executive Officer and Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2012.

Changes in Internal Control Over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

On November 14, 2012, the PaDEP sent a draft Consent Assessment of Civil Penalty (“Draft Consent”) to a subsidiary of Midstream Corporation. The Draft Consent offers to settle various alleged violations of the Pennsylvania Clean Streams Law and the PaDEP’s rules and regulations regarding erosion and sedimentation control if the Company would consent to a civil penalty. The amount of the penalty sought by the PaDEP is not material to the Company. The Company disputes many of the alleged violations and will vigorously defend its position in negotiations with the PaDEP. The alleged violations occurred during construction of the Company’s Trout Run Gathering System following historic rainfall and flooding in the fall of 2011. The Company has spent over $94 million in constructing this project.

For a discussion of various environmental and other matters, refer to Part I, Item 1 at Note 6 — Commitments and Contingencies, and Part I, Item 2 - MD&A of this report under the heading “Other Matters – Environmental Matters.”

In addition to these matters, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service, and purchased gas cost issues, among other things. While these other matters arising in the normal course of business could have a material effect on earnings and cash flows in the period in which they are resolved, they are not expected to change materially the Company’s present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

Item 1A. Risk Factors

The risk factors in Item 1A of the Company's 2012 Form 10-K have not materially changed.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

On October 1, 2012, the Company issued a total of 4,050 unregistered shares of Company common stock to the nine non-employee directors of the Company then serving on the Board of Directors of the Company, 450 shares to each such director. All of these unregistered shares were issued under the Company's 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors' services during the quarter ended December 31, 2012. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

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Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased(a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs [b]
Oct. 1-31, 2012	6,893	$51.57	-	6,971,019
Nov. 1-30, 2012	6,992	$51.58	-	6,971,019
Dec. 1-31, 2012	262,498	$53.36	-	6,971,019
Total	276,383	$53.27	-	6,971,019

[a] Represents (i) shares of common stock of the Company purchased on the open market with Company "matching contributions" for the accounts of participants in the Company's 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock options, SARs or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes. During the quarter ended December 31, 2012, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 276,383 shares purchased other than through a publicly announced share repurchase program, 20,865 were purchased for the Company's 401(k) plans and 255,518 were purchased as a result of shares tendered to the Company by holders of stock options, SARs or shares of restricted stock.

[b] In September 2008, the Company's Board of Directors authorized the repurchase of eight million shares of the Company's common stock. The repurchase program has no expiration date. The Company, however, stopped repurchasing shares after September 17, 2008. Since that time, the Company has increased its emphasis on Marcellus Shale development and pipeline expansion. As such, the Company does not anticipate repurchasing any shares in the near future.

Item 6. Exhibits

Exhibit

Number Description of Exhibit

10.1	Description of performance goals under the National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program.
10.2	Form of Restricted Stock Unit Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan.
10.3	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective December 5, 2012.
12	Statements regarding Computation of Ratios:
	Ratio of Earnings to Fixed Charges for the Twelve Months Ended December 31, 2012 and the Fiscal Years Ended September 30, 2009 through 2012.
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
32••	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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99 National Fuel Gas Company Consolidated Statements of Income for the Twelve Months Ended December 31, 2012 and 2011.

101 Interactive data files submitted pursuant to Regulation S-T: (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the three months ended December 31, 2012 and 2011, (ii) the Consolidated Statements of Comprehensive Income for the three months ended December 31, 2012 and 2011, (iii) the Consolidated Balance Sheets at December 31, 2012 and September 30, 2012, (iv) the Consolidated Statements of Cash Flows for the three months ended December 31, 2012 and 2011 and (v) the Notes to Condensed Consolidated Financial Statements.

•• In accordance with Item 601(b)(32)(ii) of Regulation S-K and SEC Release Nos. 33-8238 and 34-47986, Final Rule: Management's Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, the material contained in Exhibit 32 is "furnished" and not deemed "filed" with the SEC and is not to be incorporated by reference into any filing of the Registrant under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing, except to the extent that the Registrant specifically incorporates it by reference.

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SIGNATURES

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.

NATIONAL FUEL GAS COMPANY

(Registrant)

/s/ D. P. Bauer

D. P. Bauer

Treasurer and Principal Financial Officer

/s/ K. M. Camiolo

K. M. Camiolo

Controller and Principal Accounting Officer

Date: February 8, 2013