NATIONAL FUEL GAS CO
Form 10-Q
February 05, 2010

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

FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended December 31, 2009

OR

o **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)

New Jersey	**13-1086010**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6363 Main Street Williamsville, New York	**14221**
(Address of principal executive offices)	(Zip Code)

(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 o

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 o NO o

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES o 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, $1 par value, outstanding at January 31, 2010: 81,109,235 shares.

Table of Contents

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
Highland	Highland Forest Resources, Inc.
Horizon	Horizon Energy Development, Inc.
Horizon LFG	Horizon LFG, Inc.
Horizon Power	Horizon Power, Inc.
Midstream Corporation	National Fuel Gas Midstream Corporation
Model City	Model City Energy, LLC
National Fuel	National Fuel Gas Company
NFR	National Fuel Resources, Inc.
Registrant	National Fuel Gas Company
Seneca	Seneca Resources Corporation
Seneca Energy	Seneca Energy II, LLC
Supply Corporation	National Fuel Gas Supply Corporation

Regulatory Agencies

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
PaPUC	Pennsylvania Public Utility Commission
SEC	Securities and Exchange Commission

Other

2009 Form 10-K	The Company s Annual Report on Form 10-K for the year ended September 30, 2009
Bbl	Barrel (of oil)
Bcf	Billion cubic feet (of natural gas)
Board foot	A measure of lumber and/or timber equal to 12 inches in length by 12 inches in width by one inch in thickness.
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.
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 an 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.
Development costs	Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas.
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

GLOSSARY OF TERMS (Cont.)

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
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.
Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped 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.
Restructuring	Generally referring to partial deregulation of the pipeline and/or utility industry by statutory or regulatory process. Restructuring of federally regulated natural gas pipelines resulted in the separation (or unbundling) of gas commodity service from transportation service for wholesale and large-volume retail markets. State restructuring programs attempt to extend the same process to retail mass markets.
S&P	Standard & Poor s Rating Service
SAR	Stock-settled stock appreciation right
Stock acquisitions	Investments in corporations.
Unbundled service	A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.
VEBA	Voluntary Employees Beneficiary Association

Table of Contents

GLOSSARY OF TERMS (Concl.)

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.

INDEX

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.

This Form 10-Q contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Forward-looking statements should be read with the cautionary statements and important factors included in this Form 10-Q at Item 2 MD&A, under the heading Safe Harbor for Forward-Looking Statements. Forward-looking statements are all statements other than statements of historical fact, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction and other 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, believes, seeks, will, may, and similar expressions.

Table of Contents

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)	2009	2008
INCOME		
Operating Revenues	$ 457,011	$ 607,163
Operating Expenses		
Purchased Gas	172,787	328,733
Operation and Maintenance	94,497	100,887
Property, Franchise and Other Taxes	18,659	18,762
Depreciation, Depletion and Amortization	44,955	42,342
Impairment of Oil and Gas Producing Properties		182,811
	330,898	673,535
Operating Income (Loss)	126,113	(66,372)
Other Income (Expense):		
Income from Unconsolidated Subsidiaries	401	1,118
Impairment of Investment in Partnership		(1,804)
Interest Income	1,154	1,892
Other Income	356	4,880
Interest Expense on Long-Term Debt	(22,063)	(18,056)
Other Interest Expense	(1,384)	375
Income (Loss) Before Income Taxes	104,577	(77,967)
Income Tax Expense (Benefit)	40,078	(35,289)
Net Income (Loss) Available for Common Stock	64,499	(42,678)
EARNINGS REINVESTED IN THE BUSINESS		
Balance at October 1	948,293	953,799
	1,012,792	911,121
Adoption of Authoritative Guidance for Defined Benefit Pension and Other Post-Retirement Plans		(804)
Dividends on Common Stock (2009 - $0.335; 2008 - $0.325)	(27,129)	(25,841)
Balance at December 31	$ 985,663	$ 884,476

Earnings Per Common Share:		
Basic:		
Net Income (Loss) Available for Common Stock	$ 0.80	$ (0.54)
Diluted:		
Net Income (Loss) Available for Common Stock	$ 0.78	$ (0.53)
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	80,612,303	79,289,005
Used in Diluted Calculation	82,172,649	80,167,893

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	December 31, 2009	September 30, 2009
ASSETS		
Property, Plant and Equipment	$ 5,245,050	$ 5,183,527
Less Accumulated Depreciation, Depletion and Amortization	2,078,625	2,051,482
	3,166,425	3,132,045
Current Assets		
Cash and Temporary Cash Investments	404,401	408,053
Cash Held in Escrow	2,000	2,000
Hedging Collateral Deposits	1,092	848
Receivables Net of Allowance for Uncollectible Accounts of $42,955 and $38,334, Respectively	176,202	144,466
Unbilled Utility Revenue	55,012	18,884
Gas Stored Underground	49,042	55,862
Materials and Supplies at average cost	28,501	24,520
Other Current Assets	64,052	68,474
Deferred Income Taxes	48,621	53,863
	828,923	776,970
Other Assets		
Recoverable Future Taxes	138,435	138,435
Unamortized Debt Expense	14,249	14,815
Other Regulatory Assets	522,669	530,913
Deferred Charges	3,507	2,737
Other Investments	77,692	78,503
Investments in Unconsolidated Subsidiaries	14,728	16,257
Goodwill	5,476	5,476
Intangible Assets	21,087	21,536
Fair Value of Derivative Financial Instruments	19,791	44,817
Other	4,719	6,625
	822,353	860,114
Total Assets	$ 4,817,701	$ 4,769,129

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	December 31, 2009	September 30, 2009
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders Equity		
Common Stock, $1 Par Value Authorized 200,000,000 Shares; Issued And Outstanding 80,981,933 Shares And 80,499,915 Shares, Respectively	$ 80,982	$ 80,500
Paid in Capital	620,601	602,839
Earnings Reinvested in the Business	985,663	948,293
Total Common Shareholder Equity Before Items of Other Comprehensive Loss	1,687,246	1,631,632
Accumulated Other Comprehensive Loss	(52,702)	(42,396)
Total Comprehensive Shareholders Equity	1,634,544	1,589,236
Long-Term Debt, Net of Current Portion	1,049,000	1,249,000
Total Capitalization	2,683,544	2,838,236
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper		
Current Portion of Long-Term Debt	200,000	
Accounts Payable	108,404	90,723
Amounts Payable to Customers	94,468	105,778
Dividends Payable	27,129	26,967
Interest Payable on Long-Term Debt	17,203	32,031
Customer Advances	30,653	24,555
Customer Security Deposits	19,565	17,430
Other Accruals and Current Liabilities	19,451	18,875
Fair Value of Derivative Financial Instruments		2,148
	516,873	318,507
Deferred Credits		
Deferred Income Taxes	670,989	663,876
Taxes Refundable to Customers	67,050	67,046
Unamortized Investment Tax Credit	3,814	3,989
Cost of Removal Regulatory Liability	120,797	105,546
Other Regulatory Liabilities	116,035	120,229
Pension and Other Post-Retirement Liabilities	401,737	415,888
Asset Retirement Obligations	91,538	91,373

Other Deferred Credits	145,324	144,439
	1,617,284	1,612,386
Commitments and Contingencies		
Total Capitalization and Liabilities	$ 4,817,701	$ 4,769,129

See Notes to Condensed Consolidated Financial Statements

Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Statements of Cash Flows
(Unaudited)

(Thousands of Dollars)	Three Months Ended December 31, 2009	2008
OPERATING ACTIVITIES		
Net Income (Loss) Available for Common Stock	$ 64,499	$ (42,678)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:		
Impairment of Oil and Gas Producing Properties		182,811
Depreciation, Depletion and Amortization	44,955	42,342
Deferred Income Taxes	21,092	(69,626)
Income from Unconsolidated Subsidiaries, Net of Cash Distributions	1,599	1,032
Impairment of Investment in Partnership		1,804
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(13,437)	(5,927)
Other	7,958	6,628
Change in:		
Hedging Collateral Deposits	(244)	(3,742)
Receivables and Unbilled Utility Revenue	(67,882)	(98,914)
Gas Stored Underground and Materials and Supplies	2,839	20,971
Unrecovered Purchased Gas Costs		10,992
Prepayments and Other Current Assets	17,859	14,958
Accounts Payable	11,408	3,705
Amounts Payable to Customers	(11,310)	1,962
Customer Advances	6,098	(2,924)
Customer Security Deposits	2,135	1,354
Other Accruals and Current Liabilities	(13,536)	29,053
Other Assets	16,967	12,560
Other Liabilities	(22,667)	(6,217)
Net Cash Provided by Operating Activities	68,333	100,144
INVESTING ACTIVITIES		
Capital Expenditures	(62,135)	(84,268)
Investment in Partnership	(70)	
Other	(247)	(632)
Net Cash Used in Investing Activities	(62,452)	(84,900)
FINANCING ACTIVITIES		
Change in Notes Payable to Banks and Commercial Paper		66,000
Excess Tax Benefits Associated with Stock-Based Compensation Awards	13,437	5,927
Dividends Paid on Common Stock	(26,967)	(25,714)
Net Proceeds from Issuance of Common Stock	3,997	6,989

Net Cash Provided by (Used in) Financing Activities	(9,533)	53,202
Net Increase (Decrease) in Cash and Temporary Cash Investments	(3,652)	68,446
Cash and Temporary Cash Investments at October 1	408,053	68,239
Cash and Temporary Cash Investments at December 31	$ 404,401	$ 136,685

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Statements of Comprehensive Income
(Unaudited)

(Thousands of Dollars)	Three Months Ended December 31, 2009	2008
Net Income (Loss) Available for Common Stock	$ 64,499	$ (42,678)
Other Comprehensive Income (Loss), Before Tax:		
Foreign Currency Translation Adjustment	17	8
Unrealized Loss on Securities Available for Sale Arising During the Period	(713)	(10,032)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(4,853)	118,880
Reclassification Adjustment for Realized Gains on Derivative Financial Instruments in Net Income	(12,052)	(28,792)
Other Comprehensive Income (Loss), Before Tax	(17,601)	80,064
Income Tax Benefit Related to Unrealized Loss on Securities Available for Sale Arising During the Period	(271)	(3,791)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(2,062)	48,128
Reclassification Adjustment for Income Tax Expense on Realized Gains from Derivative Financial Instruments In Net Income	(4,962)	(11,411)
Income Taxes Net	(7,295)	32,926
Other Comprehensive Income (Loss)	(10,306)	47,138
Comprehensive Income	$ 54,193	$ 4,460

See Notes to Condensed Consolidated Financial Statements

Item 1. Financial Statements (Cont.)

National Fuel Gas Company

Notes to Condensed Consolidated Financial Statements

(Unaudited)

Note 1 Summary of Significant Accounting Policies

Principles of Consolidation. The Company consolidates its majority owned entities. The equity method is used to account for minority owned entities. 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.

Reclassification. Certain prior year amounts have been reclassified to conform with current year presentation.

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, 2009, 2008 and 2007 that are included in the Company s 2009 Form 10-K. The consolidated financial statements for the year ended September 30, 2010 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, 2009 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2010. 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 investments purchased with a maturity of generally three months or less to be cash equivalents.

At December 31, 2009, the Company accrued $15.4 million of capital expenditures in the Exploration and Production segment, the majority of which was in the Appalachian region. This amount was excluded from the Consolidated Statement of Cash Flows at December 31, 2009 since it represented a non-cash investing activity at that date.

At September 30, 2009, the Company accrued $9.1 million of capital expenditures in the Exploration and Production segment, the majority of which was in the Appalachian region. The Company also accrued $0.7 million of capital expenditures in the All Other category related to the construction of the Midstream Covington Gathering System. These amounts were excluded from the Consolidated Statement of Cash Flows at September 30, 2009 since they represented non-cash investing activities at that date. These capital expenditures were paid during the quarter ended December 31, 2009 and have been included in the Consolidated Statement of Cash Flows at December 31, 2009.

At December 31, 2008, the Company accrued $51.7 million of capital expenditures in the Exploration and Production segment, the majority of which was for lease acquisitions in the Appalachian region. This amount was excluded from the Consolidated Statement of Cash Flows at December 31, 2008 since it represented a non-cash investing activity at that date.

Table of Contents

Item 1. Financial Statements (Cont.)

At September 30, 2008, the Company accrued $16.8 million of capital expenditures related to the construction of the Empire Connector project. This amount was excluded from the Consolidated Statement of Cash Flows at September 30, 2008 since it represented a non-cash investing activity at that date. These capital expenditures were paid during the quarter ended December 31, 2008 and have been included in the Consolidated Statement of Cash Flows at December 31, 2008.

Hedging Collateral Deposits. This is an account title for cash held in margin accounts funded by the Company to serve as collateral for open hedging positions. At December 31, 2009, the Company had hedging collateral deposits of $0.2 million related to its exchange-traded futures contracts and $0.9 million related to its over-the-counter crude oil swap agreements. It is the Company s policy to not offset hedging collateral deposits paid or received against the derivative financial instruments liability or asset balances.

Cash Held in Escrow. On July 20, 2009, the Company s wholly-owned subsidiary in the Exploration and Production segment, Seneca, acquired Ivanhoe Energy s United States oil and gas operations for approximately $39.2 million in cash (including cash acquired of $4.3 million). The cash acquired at acquisition includes $2 million held in escrow at December 31, 2009 and September 30, 2009. Seneca placed this amount in escrow as part of the purchase price, and in accordance with the purchase agreement, this amount will remain in escrow for one year from the closing of the transaction provided there are no pending disputes or actions regarding obligations and liabilities required to be satisfied or discharged by Ivanhoe Energy. If no disputes occur, this cash will be released to Ivanhoe Energy.

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 $8.9 million at December 31, 2009, 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. 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 current market 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. 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. The Company s capitalized costs exceeded the full cost ceiling for the Company s oil and gas

Table of Contents

Item 1. Financial Statements (Cont.)

properties at December 31, 2008. As such, the Company recognized a pre-tax impairment of $182.8 million at December 31, 2008. Deferred income taxes of $74.6 million were recorded associated with this impairment. At December 31, 2009, the Company s capitalized costs were below the full cost ceiling for the Company s oil and gas properties. As such, an impairment charge was not required at December 31, 2009.

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

	At December 31, 2009	At September 30, 2009
Funded Status of the Pension and Other Post-Retirement Benefit Plans	$ (63,802)	$ (63,802)
Cumulative Foreign Currency Translation Adjustment	(87)	(104)
Net Unrealized Gain on Derivative Financial Instruments	8,610	18,491
Net Unrealized Gain on Securities Available for Sale	2,577	3,019
Accumulated Other Comprehensive Loss	$ (52,702)	$ (42,396)

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 reflect 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 diluted earnings per common share, the only potentially dilutive securities the Company has outstanding are stock options and stock-settled SARs. The diluted weighted average shares outstanding shown on the Consolidated Statement of Income reflects the potential dilution as a result of these stock options and stock-settled SARs as determined using the Treasury Stock Method. Stock options and stock-settled SARs that are antidilutive are excluded from the calculation of diluted earnings per common share. For the quarter ended December 31, 2009, there were no stock options and 24,000 stock-settled SARs excluded as being antidilutive. For the quarter ended December 31, 2008, there were 765,000 stock options and 365,000 stock-settled SARs excluded as being antidilutive.

New Authoritative Accounting and Financial Reporting Guidance. In September 2006, the FASB issued authoritative guidance for using fair value to measure assets and liabilities. This guidance serves to clarify the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect that fair-value measurements have on earnings. This guidance is to be applied whenever assets or liabilities are to be measured at fair value. On October 1, 2008, the Company adopted this guidance for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis. The FASB s authoritative guidance for using fair value to measure nonfinancial assets and nonfinancial liabilities on a nonrecurring basis became effective during the quarter ended December 31, 2009. The Company s nonfinancial assets and nonfinancial liabilities were not impacted by this guidance during the quarter ended December 31, 2009. The Company has identified Goodwill as being the major nonfinancial asset that may be impacted by the adoption of this guidance. The impact of this guidance will be known when the Company performs its annual test for goodwill impairment at the end of the fiscal year; however, at this time, it is not expected to be material. The Company has identified Asset Retirement Obligations as a nonfinancial liability that may be impacted by the adoption of the guidance. The impact of this guidance will be known when the Company recognizes new asset retirement obligations. However, at this time, the Company believes the impact of the guidance will be immaterial.

Table of Contents

Item 1. Financial Statements (Cont.)

In December 2007, the FASB revised authoritative guidance that significantly changes the accounting for business combinations in a number of areas including the treatment of contingent consideration, contingencies, acquisition costs, in process research and development and restructuring costs. In addition, under this guidance, changes in deferred tax asset valuation allowances and acquired income tax uncertainties in a business combination after the measurement period will impact income tax expense. This authoritative guidance became effective for the Company as of October 1, 2009. The Company will apply this guidance to future business combinations.

In December 2007, the FASB issued authoritative guidance that changes the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests (NCI) and classified as a component of equity. This new consolidation method significantly changed the accounting for transactions with minority interest holders. This authoritative guidance became effective for the Company as of October 1, 2009. This guidance currently does not have an impact on the Company s consolidated financial statements.

In June 2008, the FASB issued authoritative guidance concerning whether certain instruments granted in share-based payment transactions are participating securities. This guidance specified that unvested share-based payment awards that contain nonforfeitable rights to dividends are participating securities and shall be included in the computation of earnings per share pursuant to the two-class method. The two class method allocates undistributed earnings between common shares and participating securities. The Company adopted this guidance during the first quarter of fiscal 2010 and determined that its participating securities (restricted stock awards) have an immaterial impact on the Company s earnings per share calculation. Therefore, the Company has not presented its earnings per share pursuant to the two class method.

On December 31, 2008, the SEC issued a final rule on Modernization of Oil and Gas Reporting. The final rule modifies the SEC s reporting and disclosure rules for oil and gas reserves and aligns the full cost accounting rules with the revised disclosures. The most notable changes of the final rule include the replacement of the single day period-end pricing to value oil and gas reserves to a 12-month average of the first day of the month price for each month within the reporting period. The final rule also permits voluntary disclosure of probable and possible reserves, a disclosure previously prohibited by SEC rules. Additionally, on January 6, 2010, the FASB amended the oil and gas accounting standards to conform to the SEC final rule on Modernization of Oil and Gas Reporting. The revised reporting and disclosure requirements are effective for the Company s Form 10-K for the period ended September 30, 2010. Early adoption is not permitted. The Company is currently evaluating the impact that adoption of these rules will have on its consolidated financial statements and MD&A disclosures.

In March 2009, the FASB issued authoritative guidance that expands the disclosures required in an employer s financial statements about pension and other post-retirement benefit plan assets. The additional disclosures include more details on how investment allocation decisions are made, the plan s investment policies and strategies, the major categories of plan assets, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair value measurements using significant unobservable inputs on changes in plan assets for the period, and disclosure regarding significant concentrations of risk within plan assets. The additional disclosure requirements are required for the Company s Form 10-K for the period ended September 30, 2010. The Company is currently evaluating the impact that adoption of this authoritative guidance will have on its consolidated financial statement disclosures.

In June 2009, the FASB issued amended authoritative guidance to improve and clarify financial reporting requirements by companies involved with variable interest entities. The new guidance requires a company to perform an analysis to determine whether the company s variable interest or interests give it a controlling financial interest in a variable interest entity. The analysis also assists in identifying the primary beneficiary of a variable interest entity. This authoritative guidance is effective as of the Company s first quarter of fiscal 2011. The Company is currently evaluating the impact that adoption of this authoritative guidance will have on its consolidated financial statements.

Table of Contents

Item 1. Financial Statements (Cont.)

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 has the ability to 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 tables set 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, 2009 and September 30, 2009. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Recurring Fair Value Measures	At fair value as of December 31, 2009			
(Dollars in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Cash Equivalents	$ 385,813	$	$	$ 385,813
Derivative Financial Instruments	2,625	17,315	(149)	19,791
Other Investments	23,809			23,809
Hedging Collateral Deposits	1,092			1,092
Total	$ 413,339	$ 17,315	$ (149)	$ 430,505

Recurring Fair Value Measures	At fair value as of September 30, 2009			
(Dollars in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Cash Equivalents	$ 390,462	$	$	$ 390,462
Derivative Financial Instruments	5,312	12,536	26,969	44,817
Other Investments	24,276			24,276
Hedging Collateral Deposits	848			848
Total	$ 420,898	$ 12,536	$ 26,969	$ 460,403
Liabilities:				
Derivative Financial Instruments	$	$ 2,148	$	$ 2,148
Total	$	$ 2,148	$	$ 2,148

Cash Equivalents

The cash equivalents reported in Level 1 consist of SEC registered money market mutual funds.

Derivative Financial Instruments

At December 31, 2009, the derivative financial instruments reported in Level 1 consist of NYMEX futures contracts used in the Company s Energy Marketing and Pipeline and Storage segments (at September 30, 2009, the derivative financial instruments reported in Level 1 consist of NYMEX futures used in the Company s Energy Marketing segment). Hedging collateral deposits of $0.2 million associated with these futures contracts have been reported in Level 1 as well. The derivative financial instruments

Item 1. Financial Statements (Cont.)

reported in Level 2 consist of natural gas and some of the crude oil swap agreements used in the Company s Exploration and Production segment and natural gas swap agreements used in the Energy Marketing segment at December 31, 2009 (at September 30, 2009, the derivative financial instruments reported in Level 2 consist of natural gas swap agreements used in the Company s Exploration and Production and Energy Marketing segments). The fair value of these swap agreements is based on an internal model that uses observable inputs. At December 31, 2009, the derivative financial instruments reported in Level 3 consist of a majority of the Exploration and Production segment s crude oil swap agreements (at September 30, 2009, all of the Exploration and Production segment s crude oil swap agreements were reported as Level 3). The fair value of the crude oil swap agreements is based on an internal model that uses both observable and unobservable inputs. Based on an assessment of the counterparties credit risk, the fair market value of the price swap agreements reported as Level 2 and 3 assets have been reduced by $0.2 million and $0.9 million at December 31, 2009 and September 30, 2009, respectively. The fair market value of the price swap agreements reported as Level 2 liabilities at September 30, 2009 has been reduced by less than $0.1 million based on an assessment of the Company s credit risk. These credit reserves were determined by applying default probabilities to the anticipated cash flows that the Company is either expecting from its counterparties or expecting to pay to its counterparties.

At December 31, 2009, $0.9 million in hedging collateral deposits reported in Level 1 are associated with the Level 3 derivative financial instruments used by the Exploration and Production segment. The Company s internal model may yield a different fair value than the fair value determined by the Company s counterparties. The Company s requirement to post hedging collateral deposits is based on the fair value determined by the Company s counterparties.

Other Investments

The other investments reported in Level 1 consist of publicly traded equity securities and a publicly traded balanced equity mutual fund.

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, 2009 and 2008, respectively.

Fair Value Measurements Using Unobservable Inputs (Level 3)

		Total Gains/Losses Realized and Unrealized			
(Dollars in thousands)	October 1, 2009	Included in Earnings	Included in Other Comprehensive Income	Transfer In/Out of Level 3	December 31, 2009
Assets:					
Derivative Financial Instruments	$ 26,969	$ (3,135)[(1)]	$ (23,983)	$	$ (149)
Total	$ 26,969	$ (3,135)	$ (23,983)	$	$ (149)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months

ended
December 31,
2009.

Table of Contents

Item 1. Financial Statements (Cont.)

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Dollars in thousands)	October 1, 2008	Total Gains/Losses Realized and Unrealized Included in Earnings	Included in Other Comprehensive Income	Transfer In/Out of Level 3	December 31, 2008
Assets:					
Derivative Financial Instruments	$ 7,110	$ (3,716)[1]	$ 79,636	$	$ 83,030
Total	$ 7,110	$ (3,716)	$ 79,636	$	$ 83,030
Liabilities:					
Derivative Financial Instruments	$ (777)	$ (12,104)[1]	$ 12,881	$	$
Total	$ (777)	$ (12,104)	$ 12,881	$	$

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended December 31, 2008.

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 risk 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:

	December 31, 2009		September 30, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$ 1,249,000	$ 1,345,127	$ 1,249,000	$ 1,347,368

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 $53.9 million at December 31, 2009 and $54.2 million at September 30, 2009. The fair value of the equity mutual fund was $16.4 million at December 31, 2009 and $15.8 million at September 30, 2009. The gross unrealized loss on this equity mutual fund was $0.7 million at December 31, 2009 and $1.0 million at September 30, 2009. Management does not consider this investment to be other than temporarily impaired. The fair value of the stock of an insurance company was $7.2 million at December 31, 2009 and $8.3 million at September 30, 2009. The gross unrealized gain on this stock was $4.8 million at December 31, 2009 and $5.9 million at September 30, 2009. 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 is exposed to certain risks relating to its ongoing business operations. The primary risk managed by using derivative instruments is 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

Table of Contents

Item 1. Financial Statements (Cont.)

risk associated with forecasted gas purchases, storage of gas, and withdrawal of gas from storage to meet customer demand. The duration of the Company s hedges do not typically exceed 3 years and the majority of the positions settle within one year.

The Company has presented its net derivative assets and liabilities on its Consolidated Balance Sheets at December 31, 2009 and September 30, 2009 as shown in the table below.

Fair Values of Derivative Instruments (Dollar Amounts in Thousands)

	Asset Derivatives		Liability Derivatives	
Derivatives Designated as Hedging Instruments	**Consolidated Balance Sheet Location**	**Fair Value**	**Consolidated Balance Sheet Location**	**Fair Value**
Commodity Contracts at December 31, 2009	Fair Value of Derivative Financial Instruments	$19,791	Fair Value of Derivative Financial Instruments	$
Commodity Contracts at September 30, 2009	Fair Value of Derivative Financial Instruments	$44,817	Fair Value of Derivative Financial Instruments	$2,148

The following table discloses the fair value of derivative contracts on a gross-contract basis as opposed to the net-contract basis presentation on the Consolidated Balance Sheets at December 31, 2009 and September 30, 2009.

Derivatives Designated as Hedging Instruments	Fair Values of Derivative Instruments (Dollar Amounts in Thousands) Gross Asset Derivatives Fair Value	Gross Liability Derivatives Fair Value
Commodity Contracts at December 31, 2009	$ 61,465	$ 41,674
Commodity Contracts at September 30, 2009	$ 63,601	$ 20,932

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 same 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, 2009, 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):

Table of Contents

Item 1. Financial Statements (Cont.)

Commodity	Units
Natural Gas	33.0 Bcf (all short positions)
Crude Oil	2,665,000 Bbls (all short positions)

As of December 31, 2009, 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 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	4.1 Bcf (3.7 Bcf short positions (forecasted storage withdrawals) and 0.4 Bcf long positions (forecasted storage injections))

As of December 31, 2009, the Company s Pipeline and Storage segment have the following commodity derivative contracts (futures contracts) 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):

Commodity	Units
Natural Gas	0.3 Bcf (all short positions)

As of December 31, 2009, the Company s Exploration and Production segment had $16.3 million ($9.6 million after tax) of gains included in the accumulated other comprehensive loss balance. It is expected that $17.7 million ($10.4 million after tax) of these gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the sales of the underlying commodities are expected to occur. See Note 1, under Accumulated Other Comprehensive Loss, for the after-tax gain pertaining to derivative financial instruments (Net Unrealized Gain on Derivative Financial Instruments in Note 1 includes the Exploration and Production, Energy Marketing and Pipeline and Storage segments).

As of December 31, 2009, the Company s Energy Marketing segment had $1.7 million ($1.0 million after tax) of losses included in the accumulated other comprehensive loss balance. It is expected that $1.8 million ($1.1 million after tax) of these losses will be reclassified into the Consolidated Statement of Income within the next 12 months as the sales and purchases of the underlying commodities occur. See Note 1, under Accumulated Other Comprehensive Loss, for the after-tax gain pertaining to derivative financial instruments (Net Unrealized Gain on Derivative Financial Instruments in Note 1 includes the Exploration and Production, Energy Marketing and Pipeline and Storage segments).

As of December 31, 2009, the Company s Pipeline and Storage segment had less than $0.1 million of gains included in the accumulated other comprehensive loss balance. It is expected that the full amount will be reclassified into the Consolidated Statement of Income within the next 12 months as the sales with underlying commodities are expected to occur. See Note 1, under Accumulated Other Comprehensive Loss, for the after-tax gain pertaining to derivative financial instruments (Net Unrealized Gain on Derivative Financial Instruments in Note 1 includes the Exploration and Production, Energy Marketing and Pipeline and Storage segments).

Table of Contents

Item 1. Financial Statements (Cont.)

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended December 31, 2009 (Dollar Amounts in Thousands)

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 (Effective Portion) for the Three Months Ended December 31, 2009	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, 2009	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, 2009
Commodity Contracts Exploration & Production segment	$ (7,910)	Operating Revenue	$ 12,040	Operating Revenue	$
Commodity Contracts Energy Marketing segment	$ 3,024	Purchased Gas	$ 23	Operating Revenue	$
Commodity Contracts Pipeline & Storage segment	$ 33	Operating Revenue	$ (11)	Operating Revenue	$
Total	$ (4,853)		$ 12,052		$

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 commitments related to the injection and withdrawal of storage gas. In order to hedge fixed price sales commitments, the Company enters into long positions to mitigate the risk that after the Company enters into fixed price sales agreements with its customers, the price of natural gas increases (thereby passing up the opportunity for higher operating revenue). With fixed price purchase commitments, the Company enters into short positions to mitigate the risk that after the Company locks into fixed price purchase deals with its suppliers, the price of natural gas decreases (thereby passing up the opportunity for lower purchased gas expense). Fair value hedges related to the injection and withdrawal of storage gas impact purchased gas expense. As of December 31, 2009, the Company s Energy Marketing segment had fair value hedges covering approximately 9.3 Bcf (7.6 Bcf of fixed price sales commitments (all long positions), 1.1 Bcf of fixed price purchase commitments (all short positions), and 0.6 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.

Consolidated Statement of Income	Gain/(Loss) on Derivative	Gain/(Loss) on Commitment
Operating Revenues	$ 609,000	$ (609,000)
Purchased Gas	$ (629,000)	$ 629,000

Table of Contents

Item 1. Financial Statements (Cont.)

Derivatives in Fair Value Hedging Relationships	Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income	Amount of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income for the Three Months Ended December 31, 2009 (In thousands)	
Commodity Contracts Energy Marketing segment [1]	Operating Revenues	$	609
Commodity Contracts Energy Marketing segment [2]	Purchased Gas	$	(685)
Commodity Contracts Energy Marketing segment [3]	Purchased Gas	$	56
		$	**(20)**

(1) Represents hedging of fixed price sales commitments of natural gas.

(2) Represents hedging of fixed price purchase commitments of natural gas.

(3) Represents hedging of storage withdrawal commitments of natural gas.

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 ten counterparties. On average, the Company has $1.7 million of credit exposure per counterparty. The Company had not received any collateral from the counterparties at December 31, 2009 since 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.

As of December 31, 2009, eight of the ten 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 (the lower of the S&P or Moody s Debt Rating), 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 and the Company s credit rating declined, then additional hedging collateral deposits would be required. At December 31, 2009, the fair market value of the derivative financial instrument assets related to these eight counterparties was $14.2 million according to the Company s internal model (discussed in Note 2 Fair Value Measurements). The Company s internal model may yield a different fair value than the fair value determined by the Company s counterparties. The Company s requirement to post hedging collateral deposits is based on the fair value determined by the Company s counterparties. For its over-the-counter crude oil swap agreements, the Company was required to pay $0.9 million in hedging collateral deposits at December 31, 2009. This is discussed in Note 1 under Hedging Collateral Deposits.

For its exchange traded futures contracts, which are in an asset position, the Company had paid $0.2 million in hedging collateral as of December 31, 2009. 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 (i.e. those positions that have been settled for cash) and margin requirements. This is discussed in Note 1 under Hedging Collateral Deposits.

Table of Contents

Item 1. Financial Statements (Cont.)

Note 4 Income Taxes

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

	Three Months Ended December 31, 2009	Three Months Ended December 31, 2008
Current Income Taxes		
Federal	$ 15,070	$ 26,518
State	3,916	7,819
Deferred Income Taxes		
Federal	17,335	(54,055)
State	3,757	(15,571)
	40,078	(35,289)
Deferred Investment Tax Credit	(174)	(174)
Total Income Taxes	$ 39,904	$ (35,463)
Presented as Follows:		
Other Income	$ (174)	$ (174)
Income Tax Expense (Benefit)	40,078	(35,289)
Total Income Taxes	$ 39,904	$ (35,463)

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

	Three Months Ended December 31, 2009	Three Months Ended December 31, 2008
Income (Loss) Before Income Taxes	$ 104,403	$ (78,141)
Income Tax Expense (Benefit), Computed at Federal Statutory Rate of 35%	$ 36,541	$ (27,349)
Increase (Reduction) in Taxes Resulting From:		
State Income Taxes	4,987	(5,039)
Miscellaneous	(1,624)	(3,075)
Total Income Taxes	$ 39,904	$ (35,463)

Table of Contents

Item 1. Financial Statements (Cont.)

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

	At December 31, 2009	At September 30, 2009
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 745,363	$ 733,581
Pension and Other Post-Retirement Benefit Costs	182,807	178,440
Other	45,627	54,977
Total Deferred Tax Liabilities	973,797	966,998
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(211,143)	(212,299)
Other	(140,286)	(144,686)
Total Deferred Tax Assets	(351,429)	(356,985)
Total Net Deferred Income Taxes	$ 622,368	$ 610,013
Presented as Follows:		
Net Deferred Tax Liability/(Asset) Current	$ (48,621)	$ (53,863)
Net Deferred Tax Liability Non-Current	670,989	663,876
Total Net Deferred Income Taxes	$ 622,368	$ 610,013

As of September 30, 2009, the Company recorded a deferred tax asset relating to a federal net operating loss carryover of $25.1 million, of which $24.7 million remains at December 31, 2009. This carryover, which is available as a result of an acquisition, expires in varying amounts between 2023 and 2029. Although this loss carryover is subject to certain annual limitations, no valuation allowance was recorded because of management s determination that the amount will be fully utilized during the carryforward period.

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 $67.1 million and $67.0 million at December 31, 2009 and September 30, 2009, respectively. 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 $138.4 million at December 31, 2009 and September 30, 2009.

The Company files federal and various state income tax returns. The Internal Revenue Service (IRS) is currently conducting an examination of the Company for fiscal 2009 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 2006 and later years, IRS examinations for fiscal 2008 and prior years have been completed and the Company believes such years are effectively settled.

The Company is also subject to various routine state income tax examinations. The Company s operating subsidiaries mainly operate 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.

Table of Contents

Item 1. Financial Statements (Cont.)

Note 5 Capitalization

Common Stock. During the three months ended December 31, 2009, the Company issued 728,523 original issue shares of common stock as a result of stock option exercises. The Company also issued 3,200 original issue shares of common stock to the eight non-employee directors of the Company who receive compensation under the Company s Retainer Policy for Non-Employee Directors, as partial consideration for the directors services during the three months ended December 31, 2009. Holders of stock options 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, 2009, 249,705 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 December 31, 2009 consists of $200 million of 7.50% medium-term notes that mature in November 2010.

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. The Company has received approval from the NYDEC of a Remedial Design work plan for this site and has recorded an estimated minimum liability for remediation of this site of $15.2 million.

At December 31, 2009, 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 $18.1 million to $22.3 million. The minimum estimated liability of $18.1 million, which includes the $15.2 million discussed above, has been recorded on the Consolidated Balance Sheet at December 31, 2009. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and deferred insurance proceeds that are currently recorded as a regulatory liability on the Consolidated Balance Sheet.

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.

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 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, or have a material adverse effect on the financial condition of the Company.

Table of Contents

Item 1. Financial Statements (Cont.)

Note 7 Business Segment Information

The Company has four reportable segments: Utility, Pipeline and Storage, Exploration and Production and Energy Marketing. The division of the Company s operations into the reported 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 the reported segments and reconciliations to consolidated amounts. As stated in the 2009 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 2009 Form 10-K. There have been no material changes in the amount of assets for any operating segment from the amounts disclosed in the 2009 Form 10-K.

Quarter Ended December 31, 2009 (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	$232,404	$34,504	$106,351	$71,736	$444,995	$11,805	$ 211	$457,011
Intersegment Revenues	$ 4,514	$20,257	$	$	$ 24,771	$	$(24,771)	$
Segment Profit: Net Income (Loss)	$ 23,013	$10,354	$ 29,779	$ 1,092	$ 64,238	$ 1,166	$ (905)	$ 64,499

Quarter Ended December 31, 2008 (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	$349,637	$35,267	$ 96,712	$115,007	$596,623	$10,325	$ 215	$607,163
Intersegment Revenues	$ 4,553	$20,837	$	$	$ 25,390	$ 2,322	$(27,712)	$
Segment Profit: Net Income (Loss)	$ 22,088	$17,176	$(83,557)	$ 599	$ (43,694)	$ (868)	$ 1,884	$ (42,678)

Table of Contents

Item 1. Financial Statements (Cont.)

Note 8 Intangible Assets

The components of the Company s intangible assets were as follows (in thousands):

	At December 31, 2009			At September 30, 2009
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Net Carrying Amount
Intangible Assets Subject to Amortization:				
Long-Term Transportation Contracts	$ 4,701	$ (2,729)	$ 1,972	$ 2,071
Long-Term Gas Purchase Contracts	31,864	(12,749)	19,115	19,465
	$ 36,565	$ (15,478)	$ 21,087	$ 21,536

Aggregate Amortization Expense:	
(Thousands)	
Three Months Ended December 31, 2009	$ 449
Three Months Ended December 31, 2008	$ 554

The gross carrying amount of intangible assets subject to amortization at December 31, 2009 remained unchanged from September 30, 2009. The only activity with regard to intangible assets subject to amortization was amortization expense as shown in the table above. Amortization expense for the long-term transportation contracts is estimated to be $0.3 million for the remainder of 2010 and $0.4 million annually for 2011, 2012, 2013 and 2014. Amortization expense for the long-term gas purchase contracts is estimated to be $1.1 million for the remainder of 2010 and $1.4 million annually for 2011, 2012, 2013 and 2014.

Note 9 Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

	Retirement Plan		Other Post-Retirement Benefits	
Three months ended December 31,	2009	2008	2009	2008
Service Cost	$ 3,249	$ 2,728	$ 1,075	$ 950
Interest Cost	11,077	11,709	6,254	6,875
Expected Return on Plan Assets	(14,585)	(14,489)	(6,584)	(7,904)
Amortization of Prior Service Cost	164	183	(427)	(268)
Amortization of Transition Amount			135	566
Amortization of Losses	5,410	1,419	6,470	2,318
Net Amortization and Deferral For Regulatory Purposes (Including Volumetric Adjustments) (1)	(42)	3,240	(100)	4,339
Net Periodic Benefit Cost	$ 5,273	$ 4,790	$ 6,823	$ 6,876

(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.

Table of Contents

Item 1. Financial Statements (Cont.)

Prior to the adoption of authoritative guidance related to accounting for defined benefit pension and other postretirement plans, the Company used June 30th as the measurement date for financial reporting purposes. In 2009, in accordance with the current authoritative guidance for defined benefit pension and other postretirement plans, the Company began measuring the Plan s assets and liabilities for its pension and other post-retirement benefit plans as of September 30th, its fiscal year end. In making this change and as permitted by the current authoritative guidance, the Company recorded fifteen months of pension and post-retirement benefits expense during fiscal 2009. As allowed by the authoritative guidance, these costs were calculated using June 30, 2008 measurement date data. Three of those months pertained to the period of July 1, 2008 to September 30, 2008. The pension and other post-retirement benefit costs for that period amounted to $3.8 million and were recorded by the Company during the quarter ended December 31, 2008 as a $3.4 million increase to Other Regulatory Assets in the Company s Utility and Pipeline and Storage segments and a $0.4 million ($0.2 million after tax) adjustment to earnings reinvested in the business. In addition, for the Company s non-qualified benefit plan, benefit costs of $1.3 million were recorded by the Company during the quarter ended December 31, 2008 as a $0.4 million increase to Other Regulatory Assets in the Company s Utility segment and a $0.9 million ($0.6 million after tax) adjustment to earnings reinvested in the business.

Employer Contributions. During the three months ended December 31, 2009, the Company contributed $20.2 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $6.2 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2010, the Company does not expect to contribute to the Retirement Plan. It is likely that the Company will have to fund larger amounts to the Retirement Plan subsequent to fiscal 2010 in order to be in compliance with the Pension Protection Act of 2006. In the remainder of 2010, the Company expects to contribute in the range of $19.0 million to $20.0 million to its VEBA trusts and 401(h) accounts.

Note 10 Subsequent Events

In accordance with the authoritative guidance for subsequent events, the Company has evaluated subsequent events through February 5, 2010, which represents the filing date of this Form 10-Q with the SEC, in order to ensure that this Form 10-Q includes appropriate disclosure of events both recognized in the financial statements as of December 31, 2009, and events which occurred subsequent to December 31, 2009 but were not recognized in the financial statements. As of February 5, 2010, there were no subsequent events which required recognition or disclosure.

Table of Contents

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

OVERVIEW

The Company is a diversified energy company consisting of four reportable business segments. For the quarter ended December 31, 2009 compared to the quarter ended December 31, 2008, the Company experienced an increase in earnings of $107.2 million, primarily due to higher earnings in the Exploration and Production segment. During the quarter ended December 31, 2008, the Company recorded an impairment charge of $182.8 million ($108.2 million after tax) that did not recur during the quarter ended December 31, 2009. 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. Such costs are subject to a quarterly ceiling test prescribed by SEC Regulation S-X Rule 4-10 that determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. At December 31, 2008, due to significant declines in crude oil and natural gas commodity prices, the book value of the Company s oil and gas properties exceeded the ceiling, resulting in the impairment charge mentioned above. For further discussion of the ceiling test results at December 31, 2009 and a sensitivity analysis to changes in crude oil and natural gas commodity prices, refer to the Critical Accounting Estimates section below. For further discussion of the Company s earnings, refer to the Results of Operations section below.

From a capital resources and liquidity perspective, the Company spent $67.7 million on capital expenditures during the three months ended December 31, 2009, with approximately 70% being spent in the Exploration and Production segment. Approximately 82% of the Exploration and Production segment capital expenditures were spent in the Appalachian region, where the Company continues to emphasize the development of its acreage in the Marcellus Shale. The Company was recently the high bidder on two tracts of land in the Appalachian region of Pennsylvania at approximately $71.8 million. This transaction is expected to close in March 2010. With this expenditure and other factors, it is expected that Exploration and Production segment capital expenditures in 2010 will be $345 million, compared to the previously reported amount of $255 million. The emphasis on Marcellus Shale development will carry over into the Pipeline and Storage segment, which is anticipating the need for pipeline and storage capacity as Marcellus Shale production comes on line. While capital expenditures in the Pipeline and Storage segment were only $7.0 million during the three months ended December 31, 2009, the Company continues to see strong interest for pipeline and storage capacity in the Marcellus Shale region. If such projects in the Pipeline and Storage segment are to go forward, the most significant expenditures are expected to occur in 2011 and 2012. For further discussion of the Company s capital expenditures, refer to the Capital Resources and Liquidity section below.

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to Critical Accounting Estimates in Item 7 of the Company s 2009 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.

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 current market prices (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 in any country exceeds the ceiling, a non-cash charge must be recorded to reduce the book value of the oil and gas properties to the calculated ceiling. At December 31, 2009, the ceiling exceeded the book value of the oil and gas properties by approximately $417 million. The quoted Cushing, Oklahoma spot price for West Texas Intermediate oil at December 31, 2009 was $79.39. The quoted Henry Hub spot price for natural gas at December 31, 2009 was $5.79. (Note Because actual pricing of the Company s various producing properties varies depending on their location, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Cushing oil and Henry Hub prices, which are only indicative of current prices.) If natural gas prices used in the ceiling test calculation at December 31, 2009 had been $1 per MMBtu lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $360 million. If crude oil prices used in the ceiling test calculation at

Table of Contents

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

December 31, 2009 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $366 million. If both natural gas and crude oil prices used in the ceiling test calculation at December 31, 2009 were lower by $1 per MMBtu and $5 per Bbl, respectively, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $309 million. 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 2009 Form 10-K.

RESULTS OF OPERATIONS

Earnings

The Company earnings were $64.5 million for the quarter ended December 31, 2009 compared to a loss of $42.7 million for the quarter ended December 31, 2008. The increase in earnings of $107.2 million is primarily the result of higher earnings in the Exploration and Production segment. Higher earnings in the Utility and Energy Marketing segments as well as the All Other category also contributed to the increase. Lower earnings in the Pipeline and Storage segment and a loss in the Corporate category slightly offset these increases. The Company s loss for the quarter ended December 31, 2008 includes a non-cash $182.8 million impairment charge ($108.2 million after tax) for the Exploration and Production segment s oil and gas producing properties.

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)*	2009	2008	Increase (Decrease)
Utility	$ 23,013	$ 22,088	$ 925
Pipeline and Storage	10,354	17,176	(6,822)
Exploration and Production	29,779	(83,557)	113,336
Energy Marketing	1,092	599	493
Total Reportable Segments	64,238	(43,694)	107,932
All Other	1,166	(868)	2,034
Corporate	(905)	1,884	(2,789)
Total Consolidated	$ 64,499	$ (42,678)	$ 107,177

Utility

Utility Operating Revenues

Three Months Ended December 31 *(Thousands)*	2009	2008	Decrease
Retail Sales Revenues:			
Residential	$ 176,597	$ 272,418	$ (95,821)
Commercial	24,406	41,333	(16,927)
Industrial	1,288	2,106	(818)
	202,291	315,857	(113,566)
Transportation	30,695	32,011	(1,316)
Off-System Sales	1,691	3,732	(2,041)
Other	2,241	2,590	(349)

	$ 236,918	$ 354,190	$ (117,272)

Table of Contents

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)
Utility Throughput

Three Months Ended December 31 *(MMcf)*	2009	2008	Increase (Decrease)
Retail Sales:			
Residential	16,824	18,166	(1,342)
Commercial	2,490	2,911	(421)
Industrial	158	143	15
	19,472	21,220	(1,748)
Transportation	17,061	17,473	(412)
Off-System Sales	356	512	(156)
	36,889	39,205	(2,316)

Degree Days

Three Months Ended December 31	Normal	2009	2008	Percent Colder (Warmer) Than Normal	Percent Colder (Warmer) Than Prior Year
Buffalo	2,260	2,246	2,313	(0.6)	(2.9)
Erie	2,081	2,048	2,067	(1.6)	(0.9)

2009 Compared with 2008

Operating revenues for the Utility segment decreased $117.3 million for the quarter ended December 31, 2009 as compared with the quarter ended December 31, 2008. This decrease largely resulted from a $113.6 million decrease in retail gas sales revenues, a $2.0 million decrease in off-system sales revenues, and a $1.3 million decrease in transportation revenues. The decrease in retail gas sales revenues of $113.6 million was largely a function of the recovery of lower gas costs (subject to certain timing variations, gas costs are recovered dollar for dollar in revenues) and warmer weather. The recovery of lower gas costs resulted from a much lower cost of purchased gas. The Utility segment s average cost of purchased gas, including the cost of transportation and storage, was $7.08 per Mcf for the three months ended December 31, 2009, a decrease of 27% from the average cost of $9.70 per Mcf for the three months ended December 31, 2008.

The decrease in off-system sales revenues was largely due to a decrease in off-system sales volume. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there was not a material impact to margins. The decrease in transportation revenues of $1.3 million was primarily due to a 0.4 Bcf decrease in transportation throughput, largely the result of warmer weather.

The Utility segment s earnings for the quarter ended December 31, 2009 were $23.0 million, an increase of $0.9 million when compared with earnings of $22.1 million for the quarter ended December 31, 2008. In the New York jurisdiction, earnings increased $0.5 million. The positive earnings impact associated with lower operating expenses of $0.7 million (primarily a decrease in bad debt expense due to lower gas costs) and routine regulatory adjustments of $0.9 million were the main factors in the earnings increase. These factors were offset by an increase in interest expense ($0.9 million) stemming from the borrowing of a portion of the Company s April 2009 debt issuance. The April 2009 debt was issued at a significantly higher interest rate than the interest rates on debt that had matured in March 2009. In the Pennsylvania jurisdiction, earnings increased $0.4 million. The positive earnings impact associated with lower operating costs of $1.5 million (primarily a decrease in bad debt expense due to lower gas costs) and lower income tax expense of $1.3 million (due to a lower effective tax rate) were the main factors in the earnings increase. These factors were largely offset by lower usage per account ($0.9 million), higher interest expense

($0.9 million), the negative earnings impact of warmer weather ($0.2 million), and routine regulatory adjustments ($0.1 million). As with the New York jurisdiction, the increase in interest expense in the Pennsylvania jurisdiction is attributable to the Company s April 2009 debt issuance and the fact that it was issued at a significantly higher interest rate than the interest rates on debt that had matured in March 2009.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

The impact of weather variations on earnings in the New York 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. For the quarter ended December 31, 2009, the WNC preserved $0.2 million of earnings, as it was warmer than normal. For the quarter ended December 31, 2008, the WNC did not have a significant impact on earnings as the weather was close to normal. In periods of colder than normal weather, the WNC benefits Distribution Corporation s New York customers.

Pipeline and Storage

Pipeline and Storage Operating Revenues

Three Months Ended December 31 *(Thousands)*	2009	2008	Increase (Decrease)
Firm Transportation	$ 36,428	$ 33,105	$ 3,323
Interruptible Transportation	305	1,103	(798)
	36,733	34,208	2,525
Firm Storage Service	16,623	16,686	(63)
Interruptible Storage Service	56	7	49
Other	1,349	5,203	(3,854)
	$ 54,761	$ 56,104	$ (1,343)

Pipeline and Storage Throughput

Three Months Ended December 31 *(MMcf)*	2009	2008	Decrease
Firm Transportation	80,639	102,253	(21,614)
Interruptible Transportation	755	1,619	(864)
	81,394	103,872	(22,478)

2009 Compared with 2008

Operating revenues for the Pipeline and Storage segment decreased $1.3 million in the quarter ended December 31, 2009 as compared with the quarter ended December 31, 2008. The decrease was primarily due to a decline in efficiency gas revenues ($3.5 million) reported as part of other revenues in the table above. This decease was primarily due to lower gas prices and lower transportation volumes retained during the quarter ended December 31, 2009 as compared with the quarter ended December 31, 2008. It also reflects a lower gain, quarter over quarter, on the sale of such retained efficiency gas volumes held in inventory. Under Supply Corporation s tariff with shippers, Supply Corporation is allowed to retain a set percentage of shipper-supplied gas to cover compressor fuel costs and other operational purposes. To the extent that Supply Corporation does not need all of the gas to cover such operational needs, it is allowed to keep the excess gas as inventory. That inventory is later sold to customers. The excess gas that is retained as inventory as well as any gains resulting from the sale of such inventory represent efficiency gas revenue to Supply Corporation. Interruptible transportation revenues also decreased $0.8 million due primarily to a decrease in the gathering rate Supply Corporation is allowed to charge. Partially offsetting the decreases was an increase in firm transportation revenues of $3.3 million. This increase was primarily the result of higher revenues from the Empire Connector, which was placed in service in December 2008. While transportation volume decreased by 22.5 Bcf largely due to warmer weather and lower industrial demand, volume fluctuations generally do not have a significant impact on revenues as a result of Supply Corporation and Empire s straight fixed-variable rate design.

The Pipeline and Storage segment s earnings for the quarter ended December 31, 2009 were $10.4 million, a decrease of $6.8 million when compared with earnings of $17.2 million for the quarter ended December 31, 2008. The earnings decrease was primarily due to lower efficiency gas revenues of $2.3 million, as discussed above. Higher depreciation expense ($0.6 million), higher interest expense ($1.9 million), higher property taxes ($0.6 million), higher operating expenses ($0.6 million) and a decrease in the allowance for funds used during construction ($2.7 million) all contributed to the decrease in earnings. The decrease in allowance for funds used during construction (equity component) is a result

Table of Contents

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

of the construction of the Empire Connector, which was completed and placed in service on December 10, 2008. The increase in both depreciation expense and property taxes is primarily a result of the Empire Connector being placed in service in December 2008. The increase in operating expenses can primarily be attributed to higher pension expense. The increase in interest expense can be attributed to higher debt balances and a higher average interest rate on borrowings combined with a decrease in the allowance for borrowed funds used during construction resulting from the completion of the Empire Connector. The increase in the average interest rate stems from the Company s April 2009 debt issuance. The decreases were partially offset by the earnings impact associated with higher transportation revenues of $1.6 million, as discussed above.

Exploration and Production

Exploration and Production Operating Revenues

Three Months Ended December 31 *(Thousands)*	2009	2008	Increase (Decrease)
Gas (after Hedging)	$ 40,868	$ 41,093	$ (225)
Oil (after Hedging)	62,695	53,071	9,624
Gas Processing Plant	7,208	7,328	(120)
Other	47	417	(370)
Intrasegment Elimination [1]	(4,467)	(5,197)	730
	$ 106,351	$ 96,712	$ 9,639

(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	2009	2008	(Decrease)
Gas Production *(MMcf)*			
Gulf Coast	2,690	1,746	944
West Coast	997	1,022	(25)
Appalachia	2,801	1,851	950
Total Production	6,488	4,619	1,869
Oil Production *(Mbbl)*			
Gulf Coast	146	128	18
West Coast	684	682	2
Appalachia	11	15	(4)
Total Production	841	825	16

Average Prices

Three Months Ended December 31	2009	2008	Increase (Decrease)
Average Gas Price/Mcf			
Gulf Coast	$ 4.84	$ 7.04	$ (2.20)
West Coast	$ 4.64	$ 5.02	$ (0.38)
Appalachia	$ 5.07	$ 8.53	$ (3.46)
Weighted Average	$ 4.91	$ 7.19	$ (2.28)
Weighted Average After Hedging	$ 6.30	$ 8.90	$ (2.60)
Average Oil Price/Bbl			
Gulf Coast	$ 72.78	$ 56.19	$ 16.59
West Coast	$ 70.32	$ 48.01	$ 22.31
Appalachia	$ 84.05	$ 69.06	$ 14.99
Weighted Average	$ 70.94	$ 49.66	$ 21.28
Weighted Average After Hedging	$ 74.53	$ 64.34	$ 10.19

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

2009 Compared with 2008

Operating revenues for the Exploration and Production segment increased $9.6 million for the quarter ended December 31, 2009 as compared with the quarter ended December 31, 2008. Oil production revenue after hedging increased $9.6 million. An increase in the weighted average price of oil after hedging ($10.19 per Bbl) was the primary cause, as production levels in the Gulf Coast and West Coast regions were marginally higher in the current period. Gas production revenue was relatively flat when comparing the quarter ended December 31, 2009 to the quarter ended December 31, 2008. Increases in Gulf Coast and Appalachian production were largely offset by price decreases in those regions.

The Exploration and Production segment s earnings for the quarter ended December 31, 2009 were $29.8 million compared with a loss of $83.6 million for the quarter ended December 31, 2008, an increase of $113.4 million. The increase in earnings is primarily the result of the non-recurrence of an impairment charge of $108.2 million that was recorded in the quarter ended December 31, 2008, as discussed above. Higher crude oil prices and marginally higher crude oil production increased earnings by $5.6 million and $0.7 million, respectively. Lower lease operating expenses ($0.6 million) and lower interest expense ($0.6 million) also contributed to the increase in earnings. The decrease in lease operating expenses is primarily due to lower production taxes related to the lower production revenue from High Island 24 and 23 fields in the Gulf Coast region and lower well operating costs related to High Island 356, which is in the process of being plugged. The decrease in interest expense is primarily due to a lower average amount of debt outstanding. The increase in earnings is partially offset by higher depletion expense ($0.5 million), lower interest income ($0.8 million), higher general and administrative and other operating expenses ($0.6 million), and the earnings impact associated with higher income tax expense ($0.5 million). The increase in depletion expense is primarily due to an increase in production partially offset by a lower full cost pool balance after the impairment charge taken during the quarter ended December 31, 2008. The decrease in interest income is primarily due to lower temporary cash investment balances and lower interest rates. The increase in general and administrative and other operating expenses is mainly due to higher personnel costs.

Energy Marketing

Energy Marketing Operating Revenues

Three Months Ended December 31 *(Thousands)*	2009	2008	Decrease
Natural Gas (after Hedging)	$ 71,713	$ 114,984	$ (43,271)
Other	23	23	
	$ 71,736	$ 115,007	$ (43,271)

Energy Marketing Volume

Three Months Ended December 31	2009	2008	Increase
Natural Gas (MMcf)	14,101	13,136	965

2009 Compared with 2008

Operating revenues for the Energy Marketing segment decreased $43.3 million for the quarter ended December 31, 2009 as compared with the quarter ended December 31, 2008. The decrease is largely attributable to lower gas sales revenue, due to a lower average price of natural gas that was recovered through revenues. While volume sold increased, the majority of the increase was attributable to sales transactions undertaken at the Niagara pipeline delivery point to offset certain basis risks that the Energy Marketing segment was exposed to under certain fixed basis commodity purchase contracts for Appalachian production. These offsetting transactions had the effect of increasing revenue and volume sold with minimal impact to earnings.

Table of Contents

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

The Energy Marketing segment s earnings for the quarter ended December 31, 2009 were $1.1 million, an increase of $0.5 million when compared with earnings of $0.6 million for the quarter ended December 31, 2008. Higher margin of $0.4 million was the primary reason for the increase. The increase in margin was primarily driven by improved average margins per Mcf and lower pipeline fuel costs due to lower natural gas commodity prices.

Corporate and All Other

2009 Compared with 2008

Corporate and All Other operations recorded earnings of $0.3 million for the quarter ended December 31, 2009, a decrease of $0.7 million when compared to the earnings of $1.0 million recorded for the quarter ended December 31, 2008. The decrease in earnings was largely due to the non-recurrence of a gain resulting from a death benefit on corporate-owned life insurance policies held by the Company ($2.3 million) that occurred during the quarter ended December 31, 2008. In addition, higher interest expense of $1.4 million (primarily the result of higher borrowings at a higher interest rate due to the $250 million of 8.75% notes that were issued in April 2009) and higher income tax expense of $1.2 million further reduced earnings. The decrease in earnings was partially offset by higher margins from log and lumber sales ($1.9 million) and higher interest income ($1.0 million) due to higher average temporary cash investment balances. In addition, during the quarter ended December 31, 2008, ESNE, an unconsolidated subsidiary of Horizon Power, recorded an impairment charge of $3.6 million which did not recur. Horizon Power s 50% share of the impairment was $1.8 million ($1.1 million on an after tax basis).

Interest Income

Interest income was $0.7 million lower in the quarter ended December 31, 2009 as compared to the quarter ended December 31, 2008. Lower cash investment balances in the Exploration and Production segment and lower interest rates on such investments were the primary factors contributing to the decrease.

Other Income

Other Income decreased $4.5 million for the quarter ended December 31, 2009 as compared with the quarter ended December 31, 2008. This decrease is attributed to a $2.7 million decrease in the allowance for funds used during construction in the Pipeline and Storage segment mainly associated with the Empire Connector project. In addition, a gain resulting from a death benefit on corporate-owned life insurance policies of $2.3 million recognized during the quarter ended December 31, 2008 did not recur.

Interest Expense on Long-Term Debt

Interest on long-term debt increased $4.0 million for the quarter ended December 31, 2009 as compared with the quarter ended December 31, 2008. This increase is primarily the result of a higher average amount of long-term debt outstanding combined with higher average interest rates. In April 2009, the Company issued $250 million of 8.75% senior, unsecured notes due in May 2019. This increase was partially offset by the repayment of $100 million of 6.0% medium-term notes that matured in March 2009.

CAPITAL RESOURCES AND LIQUIDITY

The Company s primary source of cash during the three-month periods ended December 31, 2009 and December 31, 2008 consisted of cash provided by operating activities. This source of cash was supplemented by issues of new shares of common stock as a result of stock option exercises. During the quarter ended December 31, 2008, short-term borrowings also supplemented the Company s cash position. During the three months ended December 31, 2009 and December 31, 2008, the common stock used to fulfill the requirements of the Company s 401(k) plans and Direct Stock Purchase and Dividend Reinvestment Plan was obtained via open market purchases.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

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, impairment of oil and gas producing properties, impairment of investment in partnership, deferred income taxes, and income or loss from unconsolidated subsidiaries net of cash distributions.

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 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. 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 $68.3 million for the three months ended December 31, 2009, a decrease of $31.8 million when compared with the $100.1 million provided by operating activities for the three months ended December 31, 2008. In the Exploration and Production segment, cash provided by operations decreased due to lower cash receipts from the sale of oil and gas production. In the Pipeline and Storage segment, cash provided by operations decreased due to lower cash receipts from the sale of efficiency gas inventory. From a consolidated perspective, higher interest payments on long-term debt and higher contributions to the Company s tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) also contributed to the decrease in cash provided by operating activities.

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company s expenditures for long-lived assets totaled $67.8 million for the three months ended December 31, 2009 and $119.2 million for the three months ended December 31, 2008. The table below presents these expenditures:

Table of Contents

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

Total Expenditures for Long-Lived Assets

Three Months Ended December 31, (Millions)	2009	2008	Increase (Decrease)
Utility:			
Capital Expenditures	$ 12.0	$ 13.6	$ (1.6)
Pipeline and Storage:			
Capital Expenditures	7.0	19.5(3)	(12.5)
Exploration and Production:			
Capital Expenditures	47.7(1) (2)	86.4(4)	(38.7)
All Other:			
Capital Expenditures	1.0(2)		1.0
Investment in Partnership	0.1		0.1
Eliminations		(0.3) (5)	0.3
	$ 67.8	$ 119.2	$ (51.4)

(1) Amount includes $15.4 million of accrued capital expenditures at December 31, 2009, the majority of which was in the Appalachian region. This amount has been excluded from the Consolidated Statement of Cash Flows at December 31, 2009 since it represents a non-cash investing activity at that date.

(2) Capital expenditures for the Exploration and Production segment for the

three months ended December 31, 2009 exclude \$9.1 million of capital expenditures, the majority of which was in the Appalachian region. Capital expenditures for All Other for the three months ended December 31, 2009 exclude \$0.7 million of capital expenditures related to the construction of the Midstream Covington Gathering System. Both of these amounts were accrued at September 30, 2009 and paid during the three months ended December 31, 2009. These amounts were excluded from the Consolidated Statement of Cash Flows at September 30, 2009 since they represented non-cash investing activities at that date. These amounts have been included in the Consolidated

Statement of Cash Flows at December 31, 2009.

(3) Amount for the three months ended December 31, 2008 excludes \$16.8 million of capital expenditures related to the Empire Connector project accrued at September 30, 2008 and paid during the three months ended December 31, 2008. This amount was excluded from the Consolidated Statement of Cash Flows at September 30, 2008 since it represented a non-cash investing activity at that date. The amount has been included in the Consolidated Statement of Cash Flows at December 31, 2008.

(4) Amount includes \$51.7 million of accrued capital expenditures at

December 31, 2008, the majority of which was for lease acquisitions in the Appalachian region. This amount has been excluded from the Consolidated Statement of Cash Flows at December 31, 2008 since it represents a non-cash investing activity at that date.

(5) Represents $0.3 million of capital expenditures in the Pipeline and Storage segment for the purchase of pipeline facilities from the Appalachian region of the Exploration and Production segment during the quarter ended December 31, 2008.

Utility

The majority of the Utility capital expenditures for the three months ended December 31, 2009 and December 31, 2008 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, 2009 were related to additions, improvements, and replacements to this segment s transmission and gas storage systems. The majority of the Pipeline and Storage capital expenditures for the three months ended December 31, 2008 were related to the Empire Connector project, which was placed into service on December 10, 2008.

-36-

Table of Contents

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

In light of the growing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia specifically in the Marcellus Shale producing area Supply Corporation and Empire are actively pursuing several expansion projects. Supply Corporation is moving forward with two strategic compressor horsepower expansions, both supported by signed precedent agreements with Appalachian producers, designed to move anticipated Marcellus production gas to markets beyond Supply Corporation s pipeline system.

The first strategic horsepower expansion project involves new compression along Supply Corporation s Line N, increasing that line s capacity into Texas Eastern s Holbrook Station in southwestern Pennsylvania (Line N Expansion Project). This project is designed and contracted for 150,000 Dth/day of firm transportation, and will allow anticipated Marcellus production located in the vicinity of Line N to flow south and access markets off Texas Eastern s system, with a projected in-service date of November 2011. On October 20, 2009, Supply Corporation entered the FERC National Environmental Policy Act (NEPA) Pre-filing review, and is in the process of preparing an NGA Section 7(c) application to the FERC for approval of the Line N Expansion Project. The preliminary cost estimate for the Line N Expansion Project is $23 million. As of December 31, 2009, approximately $0.6 million has been spent to study the Line N Expansion Project, which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2009.

The second strategic horsepower expansion project involves the addition of compression at Supply Corporation s existing interconnect with Tennessee Gas Pipeline at Lamont, Pennsylvania, with a projected in-service date of June 2010 (Lamont Project). The Lamont Project is designed and contracted for 40,000 Dth/day of firm transportation and will afford shippers a transportation path from their anticipated Marcellus production located in Elk and Cameron Counties, Pennsylvania to markets attached to Tennessee Gas Pipeline s 300 Line. The Lamont Project will be constructed under Supply Corporation s existing blanket construction certificate authority from the FERC. The preliminary cost estimate for the Lamont Project is $6 million. As of December 31, 2009, less than $0.1 million has been spent to study the Lamont Project, which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2009.

In addition, Supply Corporation continues to actively pursue its largest planned expansion, the West-to-East (W2E) pipeline project, which is designed to transport Rockies and/or locally produced natural gas supplies to the Ellisburg/Leidy/Corning area. Supply Corporation anticipates that the development of the W2E project will occur in phases, and based on requests from the Marcellus producing community for transportation service commencing as early as 2011, Supply Corporation began a binding Open Season on August 26, 2009. This Open Season offered transportation capacity on two initial phases (Phase I and Phase II) of the W2E pipeline project. As currently envisioned, constructed in 2 phases, Phase I would be designed to transport approximately 100,000 Dth/day from the Marcellus producing area through a new 39-mile pipeline to be constructed through Elk, Cameron, and Clinton Counties to the Leidy Hub, with an anticipated in-service date of late 2011. Phase II, with a late 2012 projected in-service date, consists of an additional 43 miles of new pipeline extending through Clearfield and Jefferson Counties to Supply Corporation s Line K system and would provide additional transportation capacity of at least 325,000 Dth/day. The project also includes 25,000 horsepower of compression at two stations located along the new pipeline.

This binding Open Season concluded on October 8, 2009 with significant participation by Marcellus producers. Supply Corporation received binding requests for 175,000 Dth/day of firm transportation capacity, has fully executed precedent agreements for 100,000 Dth/day, and expects to execute the remaining agreements submitted by those shippers. Supply Corporation is pursuing post-Open Season capacity requests for the remaining Phase I and Phase II capacity. Preliminary engineering, alternate routing analysis, preliminary cost estimate and rate design have been completed. This project will require an NGA Section 7(c) application, which Supply Corporation has not filed. The capital cost of these two phases is estimated to be $260 million. As of December 31, 2009, approximately $1.0 million has been spent to study the W2E Phase I and II transportation project, which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2009.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

In conjunction with Phases I and II of the W2E transportation project, Supply Corporation plans to develop new storage capacity by expanding two of its existing storage facilities. The expansion of the East Branch and Galbraith fields, which could be completed in early 2013, provides 7.9 MMDth of incremental storage capacity and approximately 88 MDth per day of additional withdrawal deliverability. Supply Corporation expects that the availability of this incremental storage capacity will complement Phases I and II of the W2E pipeline project by providing incremental transportation throughput to and from key market interconnect points. It will also serve to balance the increasing flow of Appalachian gas supply through the western Pennsylvania area with the growing demand for gas on the East Coast. This storage expansion project will require an NGA Section 7 (c) application, which Supply Corporation has not yet filed. The preliminary cost estimate for this storage expansion project is $64 million. As of December 31, 2009, approximately $1.0 million has been spent to study this storage expansion project, which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2009. The specific timeline associated with the storage expansion will depend on market development.

Supply Corporation expects that its previously announced Appalachian Lateral project will complement W2E Phases I and II due to its strategic upstream location. The Appalachian Lateral pipeline, which is routed through several counties in central Pennsylvania where producers are actively drilling and seeking market access for their newly discovered reserves, will be able to collect and transport locally produced Marcellus shale gas to Supply Corporation s Line K corridor and subsequently through the W2E Phase I and II facilities.

Supply Corporation has closed the Appalachian Lateral Open Season and the original Rockies supply-driven W2E Open Season, while it focuses on development of the W2E Phase I and II project. Supply Corporation expects to continue marketing efforts for all remaining sections of the W2E/Appalachian Lateral project. The timeline associated with sections other than W2E Phases I and II will depend on market development.

On October 1, 2009, Empire commenced the Open Season process for an expansion project that will provide at least 300,000 Dth/day of incremental firm transportation capacity from anticipated Marcellus production at new and existing interconnection(s) along its recently completed Empire Connector line and along a proposed 16-mile 24 pipeline extension into Tioga County, Pennsylvania. Empire s preliminary cost estimate for the Tioga County Extension Project is approximately $45 million. This project would enable shippers to deliver their gas at existing Empire interconnections with Millennium Pipeline at Corning, New York, with TransCanada Pipeline at Chippawa, and with utility and power generation markets along its path, as well as to a planned new interconnection with Tennessee Gas Pipeline s 200 Line (Zone 5) in Ontario County, New York. Empire completed the non-binding Open Season process on November 25, 2009 for capacity in the Tioga County Extension Project, and has executed a binding precedent agreement with its anchor shipper for 200,000 Dth/day. Empire is in the process of finalizing binding precedent agreements with other shippers who participated in the Open Season, representing requests for at least an additional 100,000 Dth/day. On January 28, 2010, Empire entered the FERC NEPA Pre-filing review, and is in the process of preparing a NGA Section 7 (c) application it anticipates filing with the FERC for approval of the Tioga County Extension project. Empire anticipates that these facilities will be placed in-service on or after September 1, 2011. As of December 31, 2009, approximately $0.2 million has been spent to study the Tioga County Extension Project, which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2009.

The Company anticipates financing the Line N Expansion Project, the Lamont Project, Phase I and Phase II of the W2E/Appalachian Lateral project, the storage expansion project, and the Tioga County Extension Project, all of which are discussed above, with a combination of cash from operations, short-term debt, and long-term debt.

Exploration and Production

The Exploration and Production segment capital expenditures for the three months ended December 31, 2009 were primarily well drilling and completion expenditures and included approximately $1.3 million for the Gulf Coast region, $7.4 million for the West Coast region and $39.0 million for the Appalachian region. These amounts included approximately $12.8 million spent to develop proved undeveloped reserves.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

The Exploration and Production segment capital expenditures for the three months ended December 31, 2008 were primarily well drilling and completion expenditures and included approximately $11.9 million for the Gulf Coast region, substantially all of which was for the off-shore program in the shallow waters of the Gulf of Mexico, $10.4 million for the West Coast region and $64.1 million for the Appalachian region. These amounts included approximately $10.2 million spent to develop proved undeveloped reserves.

For all of 2010, the Company expects to spend $345 million on Exploration and Production segment capital expenditures. Previously reported 2010 estimated capital expenditures for the Exploration and Production segment were $255 million. Estimated capital expenditures in the Gulf Coast region will increase from $14.0 million to $18.0 million. Estimated capital expenditures in the West Coast region will increase from $17.0 million to $27.0 million. In the Appalachian region, estimated capital expenditures will increase from $224.0 million to $300.0 million. The increase in estimated capital expenditures in the Appalachian region is primarily due to the Company s planned acquisition of two tracts of land in the Appalachian region. The Company s wholly-owned subsidiary, Seneca, was the high bidder on these two tracts of land at approximately $71.8 million. The transaction is expected to close on March 12, 2010. The Company anticipates funding this transaction with cash from operations and/or short-term borrowings. The Company s estimate of drilling 55 to 75 gross wells in the Marcellus Shale during 2010 remains unchanged.

For fiscal 2011, the Company expects to spend $488 million on Exploration and Production segment capital expenditures. Previously reported fiscal 2011 estimated capital expenditures for the Exploration and Production segment were $417 million. Estimated capital expenditures in the Gulf Coast region will increase from $5.0 million to $10.0 million. Estimated capital expenditures in the West Coast region will increase from $27.0 million to $28.0 million. In the Appalachian region, estimated capital expenditures will increase from $385.0 million to $450.0 million. The Company s estimate of drilling 100 to 130 gross wells in the Marcellus Shale during 2011 remains unchanged.

For fiscal 2012, the Company expects to spend $625 million on Exploration and Production segment capital expenditures. Previously reported fiscal 2012 estimated capital expenditures for the Exploration and Production segment were $497 million. Estimated capital expenditures in the Gulf Coast region will increase from $12.0 million to $19.0 million. In the Appalachian region, estimated capital expenditures will increase from $444.0 million to $565.0 million. Estimated capital expenditures in the West Coast region will remain at the previously reported $41.0 million. The Company had previously reported that it anticipates drilling 120 to 150 gross wells in the Marcellus Shale during 2012. The Company now anticipates drilling 130 to 160 gross wells in the Marcellus Shale during 2012.

<u>All Other</u>

The majority of the All Other category s capital expenditures for long-lived assets for the three months ended December 31, 2009 were for the construction of Midstream Corporation s Covington Gathering System, as discussed below. Expenditures for long-lived assets for the three months ended December 31, 2009 also included a $0.1 million capital contribution made by NFG Midstream Processing, LLC to Whitetail Processing Plant, LLC, as discussed below.

NFG Midstream Covington, LLC, a wholly owned subsidiary of Midstream Corporation, is constructing a gathering system in Tioga County, Pennsylvania. The project, called the Covington Gathering System, is being constructed in two phases. The first phase was completed and placed in service in November 2009. The second phase is anticipated to be placed in service in June 2010. When completed, the system will consist of approximately 15 miles of gathering system at a cost of $15 million to $18 million. As of December 31, 2009, Midstream Corporation has spent approximately $8.9 million in costs related to this project.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

NFG Midstream Processing, LLC, another wholly owned subsidiary of Midstream Corporation, has a 35% ownership in Whitetail Processing Plant, LLC. The plant was placed into service in November 2009. The plant extracts natural gas liquids from local production. As of December 31, 2009, the Company invested $1.4 million related to the construction of the plant.

The Company anticipates funding the Midstream Corporation projects with cash from operations and/or short-term borrowings.

The Company continuously evaluates capital expenditures and 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, timber or 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

The Company did not have any outstanding short-term notes payable to banks or commercial paper at December 31, 2009. However, 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, and other working capital needs. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. 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 aggregate to $420.0 million, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that these lines of credit will continue to be renewed, or replaced by similar lines. The total amount available to be issued under the Company s commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million that extends through September 30, 2010.

Under the Company s committed credit facility, the Company has agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through September 30, 2010. At December 31, 2009, the Company s debt to capitalization ratio (as calculated under the facility) was .43. The constraints specified in the committed credit facility would permit an additional $1.78 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 would exceed .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. At December 31, 2009, the Company s long-term debt ratings were: BBB (S&P), Baa1 (Moody s Investor Service), and A- (Fitch Ratings Service). At December 31, 2009, the Company s commercial paper ratings were: A-2 (S&P), P-2 (Moody s Investor Service), and F2 (Fitch Ratings Service).

Under the Company s existing indenture covenants, at December 31, 2009, the Company would have been permitted to issue up to a maximum of $1.18 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 another impairment of oil and gas properties in the future, it is possible that these indenture covenants would restrict the Company s ability to issue additional long-term unsecured indebtedness. This would not preclude the Company from issuing new indebtedness to replace maturing debt.

Table of Contents

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

The Company s 1974 indenture, pursuant to which $99.0 million (or 7.9%) of the Company s long-term debt (as of December 31, 2009) 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 $300.0 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 fail to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more, or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $20.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of December 31, 2009, the Company had no debt outstanding under the committed credit facility.

The Company s embedded cost of long-term debt was 6.95% at December 31, 2009 and 6.5% at December 31, 2008. If the Company were to issue long-term debt today, its borrowing costs might be expected to be in the range of 5.5% to 6.5% depending on the maturity date.

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 Utility and the Pipeline and Storage segments, having a remaining lease commitment of approximately $25.6 million. These leases have been entered into for the use of buildings, vehicles, construction tools, meters and other items and are accounted for as operating leases.

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, 2009, the Company contributed $20.2 million to its Retirement Plan and $6.2 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2010, the Company does not expect to contribute to the Retirement Plan. It is likely that the Company will have to fund larger amounts to the Retirement Plan subsequent to fiscal 2010 in order to be in compliance with the Pension Protection Act of 2006. In the remainder of 2010, the Company expects to contribute in the range of $19.0 million to $20.0 million to its VEBA trusts and 401(h) accounts.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

Market Risk Sensitive Instruments

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 assets relate to 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 assets (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 value of the swaps represented a $0.1 million reduction to Derivative Financial Instruments Assets or 0.03% of Total Assets as shown in Part I, Item 1 at Note 2 Fair Value Measurements at December 31, 2009.

The decrease in the net fair value of the Level 3 positions from October 1, 2009 to December 31, 2009, as shown in Part I, Item 1 at Note 2, was attributable to an increase in the commodity price of crude oil 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, 2009.

The fair value of all the Company s Derivative Financial Instruments Assets was reduced by $0.2 million based on the Company s assessment of credit risk. The Company applied default probabilities to the anticipated cash flows that it was expecting from its counterparties to calculate the credit reserve.

For a complete discussion of market risk sensitive instruments, refer to Market Risk Sensitive Instruments in Item 7 of the Company s 2009 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

Base rate adjustments in both the New York and Pennsylvania jurisdictions do not reflect the recovery of purchased gas costs. Such costs are recovered through operation of the purchased gas adjustment clauses of the appropriate regulatory authorities.

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. The rate order approved a revenue increase of $1.8 million annually, together with a surcharge that would collect up to $10.8 million to recover expenses for implementation of an efficiency and conservation incentive program. The rate order further provided for a return on equity of 9.1%. In connection with the efficiency and conservation program, the rate order adopted Distribution Corporation s proposed revenue decoupling mechanism. The revenue decoupling mechanism, like others, 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. The Company surcharges or credits any difference from the average weather normalized usage per customer account. The surcharge or credit is calculated to recover total margin for the most recent twelve-month period ending December 31, and is applied to customer bills annually, beginning March 1st.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

On April 18, 2008, Distribution Corporation filed an appeal with Supreme Court, Albany County, seeking review of the rate order. The appeal contended that portions of the rate order were invalid because they failed to meet the applicable legal standard for agency decisions. Among the issues challenged by the Company were the reasonableness of the NYPSC s disallowance of expense items and the methodology used for calculating rate of return, which the appeal contended understated the Company s cost of equity. Because of the issues appealed, the case was later transferred to the Appellate Division, New York State s second-highest court. On December 31, 2009, the Appellate Division issued its Opinion and Judgment. The court upheld the NYPSC s determination relating to the authorized rate of return but also supported the Company s argument that the NYPSC improperly disallowed recovery of certain environmental clean-up costs. The court remanded that issue to the NYPSC for further proceedings consistent with its decision. The remand proceedings have not yet been initiated by the NYPSC. On February 1, 2010, the NYPSC filed a motion for permission to Appeal to the Court of Appeals, New York State s highest court, seeking appeal of the Appellate Division s annulment of that part of the rate order relating to disallowance of certain environmental clean up costs. If the NYPSC s motion is granted, the matter will be heard by the Court of Appeals. Distribution Corporation intends to oppose the NYPSC s motion. The Company cannot ascertain the outcome of the appeal proceedings at this time.

Pennsylvania Jurisdiction

Distribution Corporation currently does not have a rate case on file with the PaPUC. Distribution Corporation s current tariff in its Pennsylvania jurisdiction was last 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. The rate settlement approved by the FERC on February 9, 2007 requires Supply Corporation to make a general rate filing to be effective December 1, 2011, and bars Supply Corporation from making a general rate filing before then, with some exceptions specified in the settlement.

Empire s new facilities (the Empire Connector project) were placed into service on December 10, 2008. As of that date, Empire became an interstate pipeline subject to FERC regulation, performing services under a FERC-approved tariff and at FERC-approved rates. The December 21, 2006 FERC order issuing Empire its Certificate of Public Convenience and Necessity requires Empire to file a cost and revenue study at the FERC, within three years after the in-service date, in conjunction with which Empire will either justify Empire s existing recourse rates or propose alternative rates.

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.

The Company has agreed with the NYDEC to remediate a former manufactured gas plant site located in New York. The Company has received approval from the NYDEC of a Remedial Design work plan for this site and has recorded an estimated minimum liability for remediation of this site of $15.2 million.

At December 31, 2009, 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 $18.1 million to $22.3 million. The minimum estimated liability of $18.1 million, which includes the $15.2 million discussed above, has been recorded on the Consolidated Balance Sheet at December 31, 2009. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and deferred insurance proceeds that are currently recorded as a regulatory liability on the Consolidated Balance Sheet.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussions. If enacted or adopted, 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. Proposed measures could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities. 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 or other factors could adversely impact the Company.

New Authoritative Accounting and Financial Reporting Guidance

In September 2006, the FASB issued authoritative guidance for using fair value to measure assets and liabilities. This guidance serves to clarify the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect that fair-value measurements have on earnings. This guidance is to be applied whenever assets or liabilities are to be measured at fair value. On October 1, 2008, the Company adopted this guidance for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis. The FASB s authoritative guidance for using fair value to measure nonfinancial assets and nonfinancial liabilities on a nonrecurring basis became effective during the quarter ended December 31, 2009. The Company s nonfinancial assets and nonfinancial liabilities were not impacted by this guidance during the quarter ended December 31, 2009. The Company has identified Goodwill as being the major nonfinancial asset that may be impacted by the adoption of this guidance. The impact of this guidance will be known when the Company performs its annual test for goodwill impairment at the end of the fiscal year; however, at this time, it is not expected to be material. The Company has identified Asset Retirement Obligations as a nonfinancial liability that may be impacted by the adoption of the guidance. The impact of this guidance will be known when the Company recognizes new asset retirement obligations. However, at this time, the Company believes the impact of the guidance will be immaterial.

In December 2007, the FASB revised authoritative guidance that significantly changes the accounting for business combinations in a number of areas including the treatment of contingent consideration, contingencies, acquisition costs, in process research and development and restructuring costs. In addition, under this guidance, changes in deferred tax asset valuation allowances and acquired income tax uncertainties in a business combination after the measurement period will impact income tax expense. This authoritative guidance became effective for the Company as of October 1, 2009. The Company will apply this guidance to future business combinations.

In December 2007, the FASB issued authoritative guidance that changes the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests (NCI) and classified as a component of equity. This new consolidation method significantly changed the accounting for transactions with minority interest holders. This authoritative guidance became effective for the Company as of October 1, 2009. This guidance currently does not have an impact on the Company s consolidated financial statements.

In June 2008, the FASB issued authoritative guidance concerning whether certain instruments granted in share-based payment transactions are participating securities. This guidance specified that unvested share-based payment awards that contain nonforfeitable rights to dividends are participating securities and shall be included in the computation of earnings per share pursuant to the two-class method. The two class method allocates undistributed earnings between common shares and participating securities. The Company adopted this guidance during the first quarter of fiscal 2010 and determined that its participating securities (restricted stock awards) have an immaterial impact on the Company s earnings per share calculation. Therefore, the Company has not presented its earnings per share pursuant to the two class method.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

On December 31, 2008, the SEC issued a final rule on Modernization of Oil and Gas Reporting. The final rule modifies the SEC s reporting and disclosure rules for oil and gas reserves and aligns the full cost accounting rules with the revised disclosures. The most notable changes of the final rule include the replacement of the single day period-end pricing to value oil and gas reserves to a 12-month average of the first day of the month price for each month within the reporting period. The final rule also permits voluntary disclosure of probable and possible reserves, a disclosure previously prohibited by SEC rules. Additionally, on January 6, 2010, the FASB amended the oil and gas accounting standards to conform to the SEC final rule on Modernization of Oil and Gas Reporting. The revised reporting and disclosure requirements are effective for the Company s Form 10-K for the period ended September 30, 2010. Early adoption is not permitted. The Company is currently evaluating the impact that adoption of these rules will have on its consolidated financial statements and MD&A disclosures.

In March 2009, the FASB issued authoritative guidance that expands the disclosures required in an employer s financial statements about pension and other post-retirement benefit plan assets. The additional disclosures include more details on how investment allocation decisions are made, the plan s investment policies and strategies, the major categories of plan assets, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair value measurements using significant unobservable inputs on changes in plan assets for the period, and disclosure regarding significant concentrations of risk within plan assets. The additional disclosure requirements are required for the Company s Form 10-K for the period ended September 30, 2010. The Company is currently evaluating the impact that adoption of this authoritative guidance will have on its consolidated financial statement disclosures.

In June 2009, the FASB issued amended authoritative guidance to improve and clarify financial reporting requirements by companies involved with variable interest entities. The new guidance requires a company to perform an analysis to determine whether the company s variable interest or interests give it a controlling financial interest in a variable interest entity. The analysis also assists in identifying the primary beneficiary of a variable interest entity. This authoritative guidance is effective as of the Company s first quarter of fiscal 2011. The Company is currently evaluating the impact that adoption of this authoritative guidance will have on its consolidated financial statements.

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, 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, believes, seek 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 forward-looking statements contained herein are based on various assumptions, many of which are based, in turn, upon further assumptions. The Company s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including, without limitation, management s examination of historical operating trends, data contained in the Company s records and other data available from third parties, but there can

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)
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. Financial and economic conditions, including the availability of credit, and their effect on the Company s ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments;

2. Occurrences affecting the Company s ability to obtain financing under credit lines or other credit facilities or through the issuance of commercial paper, other short-term notes or debt or equity securities, including any downgrades in the Company s credit ratings and changes in interest rates and other capital market conditions;

3. 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;

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

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

6. Changes in demographic patterns and weather conditions;

7. Changes in the availability and/or price of natural gas or oil and the effect of such changes on the accounting treatment of derivative financial instruments or the valuation of the Company s natural gas and oil reserves;

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

9. Uncertainty of oil and gas reserve estimates;

10. 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, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, and the need to obtain governmental approvals and permits and comply with environmental laws and regulations;

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

12. Changes in the availability and/or price of derivative financial instruments;

13. Changes in the price differentials between oil having different quality and/or different geographic locations, or changes in the price differentials between natural gas having different heating values and/or different geographic locations;

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

15. The nature and projected profitability of pending and potential projects and other investments, and the ability to obtain necessary governmental approvals and permits;

16. Significant differences between the Company s projected and actual capital expenditures and operating expenses, and unanticipated project delays or changes in project costs or plans;

Table of Contents

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Concl.)

17. Inability to obtain new customers or retain existing ones;

18. Significant changes in competitive factors affecting the Company;

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

20. Unanticipated impacts of restructuring initiatives in the natural gas and electric industries;

21. Ability to successfully identify and finance acquisitions or other investments and ability to operate and integrate existing and any subsequently acquired business or properties;

22. Changes in 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;

23. Significant changes in tax rates or policies or in rates of inflation or interest;

24. Significant changes in the Company s relationship with its employees or contractors and the potential adverse effects if labor disputes, grievances or shortages were to occur;

25. Changes in accounting principles or the application of such principles to the Company;

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

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

28. 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 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, 2009.

Table of Contents

Item 4. Controls and Procedures (Concl.)

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, 2009 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

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 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.

Item 1A. Risk Factors

The risk factors in Item 1A of the Company s 2009 Form 10-K have not materially changed other than as set forth below. The first two risk factors presented below supersede the risk factors having the same captions in the 2009 Form 10-K; the third risk factor supplements the risk factors in the 2009 Form 10-K. Each risk factor should otherwise be read in conjunction with all of the risk factors disclosed in the 2009 Form 10-K.

The amount and timing of actual future oil and natural gas production and the cost of drilling are difficult to predict and may vary significantly from reserves and production estimates, which may reduce the Company s earnings.

There are many risks in developing oil and natural gas, including numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures. The future success of the Company s Exploration and Production segment depends on its ability to develop additional oil and natural gas reserves that are economically recoverable, and its failure to do so may reduce the Company s earnings. The total and timing of actual future production may vary significantly from reserves and production estimates. The Company s drilling of development wells can involve significant risks, including those related to timing, success rates, and cost overruns, and these risks can be affected by lease and rig availability, geology, and other factors. Drilling for oil and natural gas can be unprofitable, not only from non-productive wells, but from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, weather conditions, governmental requirements, including completion of environmental impact analyses and compliance with other environmental laws and regulations, and shortages or delays in the delivery of equipment and services can delay drilling operations or result in their cancellation. The cost of drilling, completing, and operating wells is often uncertain, and new wells may not be productive or the Company may not recover all or any portion of its investment. Production can also be delayed or made uneconomic if there is insufficient gathering, processing and transportation capacity available at an economic price to get that production to a location where it can be profitably sold. Without continued successful exploitation or acquisition activities, the Company s reserves and revenues will decline as a result of its current reserves being depleted by production. The Company cannot assure you that it will be able to find or acquire additional reserves at acceptable costs.

Table of Contents

Item 1A. Risk Factors (Concl.)

Environmental regulation significantly affects the Company s business.

The Company s business operations are subject to federal, state, and local laws and regulations relating to environmental protection. These laws and regulations concern the generation, storage, transportation, disposal or discharge of contaminants and greenhouse gases into the environment, the reporting of such matters, and the general protection of public health, natural resources, wildlife and the environment. Costs of compliance and liabilities could negatively affect the Company s results of operations, financial condition and cash flows. In addition, compliance with environmental laws and regulations could require unexpected capital expenditures at the Company s facilities or delay or cause the cancellation of expansion projects or oil and natural gas drilling activities. Because the costs of complying with environmental regulations are significant, additional regulation could negatively affect the Company s business. Although the Company cannot predict the impact of the interpretation or enforcement of EPA standards or other federal, state and local regulations, the Company s costs could increase if environmental laws and regulations become more strict.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussions. If enacted or adopted, 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. Proposed measures could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities. 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.

Increased regulation of exploration and production activities, including hydraulic fracturing, could adversely impact the Company.

Due to the burgeoning Marcellus Shale play in the northeast United States, together with the fiscal difficulties faced by state governments in New York and Pennsylvania, various state legislative and regulatory initiatives regarding the exploration and production business are possible. These initiatives could include new severance taxes for oil and gas production and new statutes and regulations governing hydraulic fracturing of wells, surface owners rights and damage compensation, the spacing of wells, and environmental and safety issues regarding natural gas pipelines. Additionally, legislative initiatives in the U.S. Congress could negatively impact the hydraulic fracturing process. If adopted, any such new state or federal legislation or regulation could lead to operational delays, increased operating costs, additional regulatory burdens and increased risks of litigation for the Company s Exploration and Production segment.

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

On October 1, 2009, the Company issued a total of 3,200 unregistered shares of Company common stock to the eight non-employee directors of the Company then serving on the Board of Directors of the Company and receiving compensation under the Company s Retainer Policy for Non-Employee Directors, 400 shares to each such director. All of these unregistered shares were issued as partial consideration for such directors services during the quarter ended December 31, 2009. These transactions were exempt from registration under Section 4(2) of the Securities Act of 1933, as transactions not involving a public offering.

Table of Contents

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds (Concl.)
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, 2009	7,949	$48.77		6,971,019
Nov. 1-30, 2009	8,423	$47.12		6,971,019
Dec. 1-31, 2009	257,886	$51.28		6,971,019
Total	274,258	$51.08		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 or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes. During the

quarter ended December 31, 2009, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 274,258 shares purchased other than through a publicly announced share repurchase program, 24,553 were purchased for the Company s 401(k) plans and 249,705 were purchased as a result of shares tendered to the Company by holders of stock options or shares of restricted stock.

(b) In December 2005, the Company s Board of Directors authorized the repurchase of up to eight million shares of the Company s common stock. The Company completed the repurchase of the eight million shares during 2008. In September 2008, the Company s Board of Directors authorized the repurchase of an additional eight million shares of the Company s common stock. The Company, however, stopped repurchasing shares after September 17, 2008 in light of the unsettled nature of the credit markets. However, such repurchases may be made in the future, either in the open market or through private transactions.

Item 6. Exhibits

(a) Exhibits

Exhibit Number	Description of Exhibit
10.1	Description of long-term performance incentives under the National Fuel Gas Company Performance Incentive Program.
10.2	Description of performance goals under the Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program.
10.3	National Fuel Gas Company Executive Annual Cash Incentive Program.
12	Statements regarding Computation of Ratios:
	Ratio of Earnings to Fixed Charges for the Twelve Months Ended December 31, 2009 and the Fiscal Years Ended September 30, 2006 through 2009.
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.

Table of Contents

Item 6. Exhibits (Concl.)

31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
32	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	National Fuel Gas Company Consolidated Statement of Income for the Twelve Months Ended December 31, 2009 and 2008.

Table of Contents

SIGNATURE

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

NATIONAL FUEL GAS COMPANY
(Registrant)

/s/ R. J. Tanski
R. J. Tanski
Treasurer and Principal Financial Officer

/s/ K. M. Camiolo
K. M. Camiolo
Controller and Principal Accounting Officer

Date: February 5, 2010