NATIONAL FUEL GAS CO
Form 10-Q
August 06, 2010

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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 June 30, 2010

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.)
6**363 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 þ NO o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or 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 July 31, 2010: 81,970,322 shares.

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GLOSSARY OF TERMS

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

National Fuel Gas Companies

Company	The Registrant, the Registrant and its subsidiaries or the Registrant s subsidiaries as appropriate in the context of the disclosure
Distribution Corporation	National Fuel Gas Distribution Corporation
Empire	Empire Pipeline, Inc.
ESNE	Energy Systems North East, LLC
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.
Precedent Agreement	An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called conditions precedent) happen, usually within a specified time.
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 industries by a statutory or regulatory process. Restructuring of federally regulated natural gas pipelines has 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 Ratings Service
SAR	Stock appreciation right
Stock acquisitions	Investments in corporations.

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GLOSSARY OF TERMS (Concl.)

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
WNC	Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

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EX-101 LABELS LINKBASE DOCUMENT
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EX-101 DEFINITION LINKBASE DOCUMENT

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.

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Part I. Financial Information
Item 1. Financial Statements

National Fuel Gas Company
Consolidated Statements of Income and Earnings
Reinvested in the Business
(Unaudited)

(Thousands of Dollars, Except Per Common Share Amounts)	Three Months Ended June 30, 2010	2009
INCOME		
Operating Revenues	$ 354,127	$ 367,111
Operating Expenses		
Purchased Gas	98,400	126,969
Operation and Maintenance	97,388	91,679
Property, Franchise and Other Taxes	18,605	17,576
Depreciation, Depletion and Amortization	50,588	43,659
	264,981	279,883
Operating Income	89,146	87,228
Other Income (Expense):		
Income from Unconsolidated Subsidiaries	624	627
Interest Income	569	1,460
Other Income	851	1,522
Interest Expense on Long-Term Debt	(21,115)	(21,756)
Other Interest Expense	(1,874)	(2,539)
Income Before Income Taxes	68,201	66,542
Income Tax Expense	25,616	23,638
Net Income Available for Common Stock	42,585	42,904
EARNINGS REINVESTED IN THE BUSINESS		
Balance at April 1	1,038,869	932,119
	1,081,454	975,023
Dividends on Common Stock (2010 - $0.345 per share; 2009 - $0.335 per share)	(28,278)	(26,761)
Balance at June 30	$ 1,053,176	$ 948,262

Earnings Per Common Share:

Basic:				
Net Income Available for Common Stock	$	0.52	$	0.54
Diluted:				
Net Income Available for Common Stock	$	0.51	$	0.53
Weighted Average Common Shares Outstanding:				
Used in Basic Calculation		81,801,377		79,551,195
Used in Diluted Calculation		82,970,921		80,391,402

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Statements of Income and Earnings
Reinvested in the Business
(Unaudited)

(Thousands of Dollars, Except Per Common Share Amounts)	Nine Months Ended June 30, 2010	2009
INCOME		
Operating Revenues	$ 1,482,518	$ 1,778,919
Operating Expenses		
Purchased Gas	605,617	941,171
Operation and Maintenance	308,903	311,496
Property, Franchise and Other Taxes	57,719	56,709
Depreciation, Depletion and Amortization	142,433	127,715
Impairment of Oil and Gas Producing Properties		182,811
	1,114,672	1,619,902
Operating Income	367,846	159,017
Other Income (Expense):		
Income from Unconsolidated Subsidiaries	1,696	2,719
Impairment of Investment in Partnership		(1,804)
Interest Income	2,049	4,358
Other Income	2,473	7,350
Interest Expense on Long-Term Debt	(65,238)	(57,357)
Other Interest Expense	(5,264)	(5,013)
Income Before Income Taxes	303,562	109,270
Income Tax Expense	116,050	35,560
Net Income Available for Common Stock	187,512	73,710
EARNINGS REINVESTED IN THE BUSINESS		
Balance at October 1	948,293	953,799
	1,135,805	1,027,509
Adoption of Authoritative Guidance for Defined Benefit Pension and Other Post-Retirement Plans		(804)
Dividends on Common Stock (2010 - $1.015 per share; 2009 - $0.985 per share)	(82,629)	(78,443)
Balance at June 30	$ 1,053,176	$ 948,262

Earnings Per Common Share:		
Basic:		
Net Income Available for Common Stock	$ 2.31	$ 0.93
Diluted:		
Net Income Available for Common Stock	$ 2.27	$ 0.92
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	81,178,000	79,450,838
Used in Diluted Calculation	82,556,730	80,248,787

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	June 30, 2010	September 30, 2009
ASSETS		
Property, Plant and Equipment	$ 5,518,060	$ 5,184,844
Less Accumulated Depreciation, Depletion and Amortization	2,164,383	2,051,482
	3,353,677	3,133,362
Current Assets		
Cash and Temporary Cash Investments	458,847	408,053
Cash Held in Escrow	2,000	2,000
Hedging Collateral Deposits	8,222	848
Receivables Net of Allowance for Uncollectible Accounts of $40,786 and $38,334, Respectively	143,684	144,466
Unbilled Utility Revenue	12,957	18,884
Gas Stored Underground	27,245	55,862
Materials and Supplies at average cost	32,753	24,520
Other Current Assets	42,639	68,474
Deferred Income Taxes	32,893	53,863
	761,240	776,970
Other Assets		
Recoverable Future Taxes	138,435	138,435
Unamortized Debt Expense	13,116	14,815
Other Regulatory Assets	518,225	530,913
Deferred Charges	6,447	2,737
Other Investments	76,354	78,503
Investments in Unconsolidated Subsidiaries	14,037	14,940
Goodwill	5,476	5,476
Intangible Assets	20,188	21,536
Fair Value of Derivative Financial Instruments	41,897	44,817
Other	269	6,625
	834,444	858,797
Total Assets	$ 4,949,361	$ 4,769,129

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	June 30, 2010	September 30, 2009
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders Equity		
Common Stock, $1 Par Value Authorized - 200,000,000 Shares; Issued and Outstanding 81,965,317 Shares and 80,499,915 Shares, Respectively	$ 81,965	$ 80,500
Paid in Capital	644,751	602,839
Earnings Reinvested in the Business	1,053,176	948,293
Total Common Shareholder Equity Before Items of Other Comprehensive Loss	1,779,892	1,631,632
Accumulated Other Comprehensive Loss	(38,153)	(42,396)
Total Comprehensive Shareholders Equity	1,741,739	1,589,236
Long-Term Debt, Net of Current Portion	1,049,000	1,249,000
Total Capitalization	2,790,739	2,838,236
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper		
Current Portion of Long-Term Debt	200,000	
Accounts Payable	106,087	90,723
Amounts Payable to Customers	51,014	105,778
Dividends Payable	28,278	26,967
Interest Payable on Long-Term Debt	17,203	32,031
Customer Advances	1,029	24,555
Customer Security Deposits	18,618	17,430
Other Accruals and Current Liabilities	65,244	18,875
Fair Value of Derivative Financial Instruments	2,776	2,148
	490,249	318,507
Deferred Credits		
Deferred Income Taxes	735,558	663,876
Taxes Refundable to Customers	67,057	67,046
Unamortized Investment Tax Credit	3,463	3,989
Cost of Removal Regulatory Liability	123,357	105,546
Other Regulatory Liabilities	86,106	120,229
Pension and Other Post-Retirement Liabilities	420,361	415,888
Asset Retirement Obligations	92,601	91,373

Other Deferred Credits	139,870	144,439
	1,668,373	1,612,386
Commitments and Contingencies		
Total Capitalization and Liabilities	$ 4,949,361	$ 4,769,129

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

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

(Thousands of Dollars)	Nine Months Ended June 30, 2010	2009
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$ 187,512	$ 73,710
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Impairment of Oil and Gas Producing Properties		182,811
Depreciation, Depletion and Amortization	142,433	127,715
Deferred Income Taxes	63,813	(85,494)
Income from Unconsolidated Subsidiaries, Net of Cash Distributions	904	180
Impairment of Investment in Partnership		1,804
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(13,207)	(5,927)
Other	7,884	11,751
Change in:		
Hedging Collateral Deposits	(7,374)	(6,358)
Receivables and Unbilled Utility Revenue	6,676	(5,520)
Gas Stored Underground and Materials and Supplies	20,384	71,491
Unrecovered Purchased Gas Costs		35,808
Prepayments and Other Current Assets	39,043	37,904
Accounts Payable	127	(82,146)
Amounts Payable to Customers	(54,764)	43,019
Customer Advances	(23,526)	(29,788)
Customer Security Deposits	1,188	3,314
Other Accruals and Current Liabilities	30,961	162,903
Other Assets	29,197	(8,517)
Other Liabilities	(11,358)	(14,453)
Net Cash Provided by Operating Activities	419,893	514,207
INVESTING ACTIVITIES		
Capital Expenditures	(327,513)	(240,312)
Cash Held in Escrow		(2,000)
Net Proceeds from Sale of Oil and Gas Producing Properties		3,701
Other	(273)	(1,674)
Net Cash Used in Investing Activities	(327,786)	(240,285)
FINANCING ACTIVITIES		
Excess Tax Benefits Associated with Stock-Based Compensation Awards	13,207	5,927
Net Proceeds from Issuance of Long-Term Debt		247,780

Reduction of Long-Term Debt		(100,000)
Dividends Paid on Common Stock	(81,318)	(77,398)
Net Proceeds from Issuance of Common Stock	26,798	14,760
Net Cash Provided by (Used in) Financing Activities	(41,313)	91,069
Net Increase in Cash and Temporary Cash Investments	50,794	364,991
Cash and Temporary Cash Investments at October 1	408,053	68,239
Cash and Temporary Cash Investments at June 30	$ 458,847	$ 433,230

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

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

(Thousands of Dollars)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009
Net Income Available for Common Stock	$ 42,585	$ 42,904
Other Comprehensive Income (Loss), Before Tax:		
Foreign Currency Translation Adjustment	77	(42)
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(3,361)	3,775
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	16,528	(24,446)
Reclassification Adjustment for Realized Gains on Derivative Financial Instruments in Net Income	(11,830)	(24,853)
Other Comprehensive Income (Loss), Before Tax	1,414	(45,566)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(1,271)	1,429
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	6,794	(9,950)
Reclassification Adjustment for Income Tax Expense on Realized Gains on Derivative Financial Instruments in Net Income	(4,858)	(10,108)
Income Taxes Net	665	(18,629)
Other Comprehensive Income (Loss)	749	(26,937)
Comprehensive Income	$ 43,334	$ 15,967

(Thousands of Dollars)	Nine Months Ended June 30, 2010	Nine Months Ended June 30, 2009
Net Income Available for Common Stock	$ 187,512	$ 73,710
Other Comprehensive Income, Before Tax:		
Foreign Currency Translation Adjustment	140	(1)
Unrealized Loss on Securities Available for Sale Arising During the Period	(2,916)	(9,202)
Unrealized Gain on Derivative Financial Instruments Arising During the Period	39,308	127,357
Reclassification Adjustment for Realized Gains on Derivative Financial Instruments in Net Income	(29,472)	(93,260)
Other Comprehensive Income, Before Tax	7,060	24,894

Income Tax Benefit Related to Unrealized Loss on Securities Available for Sale Arising During the Period	(1,104)	(3,475)
Income Tax Expense Related to Unrealized Gain on Derivative Financial Instruments Arising During the Period	16,041	51,576
Reclassification Adjustment for Income Tax Expense on Realized Gains on Derivative Financial Instruments in Net Income	(12,120)	(37,478)
Income Taxes Net	2,817	10,623
Other Comprehensive Income	4,243	14,271
Comprehensive Income	$ 191,755	$ 87,981

See Notes to Condensed Consolidated Financial Statements

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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 nine months ended June 30, 2010 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 debt instruments purchased with a maturity of generally three months or less to be cash equivalents.

At June 30, 2010, the Company accrued $24.3 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 June 30, 2010 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 for the nine months ended June 30, 2010.

At June 30, 2009, the Company accrued $9.4 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 June 30, 2009 since it represents a non-cash investing activity at that date.

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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 for the nine months ended June 30, 2009.

Hedging Collateral Deposits. This is an account title for cash held in margin accounts funded by the Company to serve as collateral for hedging positions. At June 30, 2010, the Company had hedging collateral deposits of $6.4 million related to its exchange-traded futures contracts and $1.8 million related to its over-the-counter crude oil swap agreements. In accordance with its accounting policy, the Company does not offset hedging collateral deposits paid or received against related derivative financial instrument 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 June 30, 2010 and September 30, 2009. Seneca placed this amount in escrow as part of the purchase price. Currently, the Company and Ivanhoe Energy are negotiating a final resolution to the issue of whether Ivanhoe Energy is entitled to some or all of the amount held in escrow.

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 $44.6 million at June 30, 2010, is reduced to zero by September 30 of each year as the inventory is replenished.

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

Capitalized costs include costs related to unproved properties, which are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. Such costs amounted to $192.0 million at June 30, 2010. 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

Item 1. Financial Statements (Cont.)

capitalized costs exceeded the full cost ceiling for the Company s oil and gas 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 June 30, 2010, the Company s capitalized costs were below the full cost ceiling for the Company s oil and gas properties. As a result, an impairment charge was not required at June 30, 2010.

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

	At June 30, 2010	At September 30, 2009
Funded Status of the Pension and Other Post-Retirement Benefit Plans	$ (63,802)	$ (63,802)
Cumulative Foreign Currency Translation Adjustment	36	(104)
Net Unrealized Gain on Derivative Financial Instruments	24,406	18,491
Net Unrealized Gain on Securities Available for Sale	1,207	3,019
Accumulated Other Comprehensive Loss	$ (38,153)	$ (42,396)

Earnings Per Common Share. Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the only potentially dilutive securities the Company has outstanding are stock options and SARs. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these stock options and SARs as determined using the Treasury Stock Method. Stock options and SARs that are antidilutive are excluded from the calculation of diluted earnings per common share. For both the quarter and nine months ended June 30, 2010, there were no stock options excluded as being antidilutive. There were 544,500 and 237,538 SARs excluded as being antidilutive for the quarter and nine months ended June 30, 2010, respectively. For both the quarter and nine months ended June 30, 2009, there were 765,000 stock options excluded as being antidilutive. In addition, there were 365,000 SARs excluded as being antidilutive for both the quarter and nine months ended June 30, 2009.

Stock-Based Compensation. During the nine months ended June 30, 2010, the Company granted 520,500 performance-based SARs having a weighted average exercise price of $52.10 per share. The weighted average grant date fair value of these SARs was $12.06 per share. These SARs may be settled in cash, in shares of common stock of the Company, or in a combination of cash and shares of common stock of the Company, as determined by the Company. These SARs are considered equity awards under the current authoritative guidance for stock-based compensation. The accounting for those SARs is the same as the accounting for stock options. There were no SARs granted during the quarter ended June 30, 2010. The performance-based SARs granted during the nine months ended June 30, 2010 vest and become exercisable annually in one-third increments, provided that a performance condition is met. The performance condition for each fiscal year, generally stated, is an increase over the prior fiscal year of at least five percent in certain oil and natural gas production of the Exploration and Production segment. The weighted average grant date fair value of these performance-based SARs granted during the nine months ended June 30, 2010 was estimated on the date of grant using the same accounting treatment that is applied for stock options, and assumes that the performance conditions specified will be achieved. If such conditions are not met or it is not considered probable that such conditions will be met, no compensation expense is recognized and any previously recognized compensation expense is reversed.

There were no stock options granted during the quarter or nine months ended June 30, 2010. The Company granted 4,000 restricted share awards (non-vested stock as defined by the current accounting literature) during the nine months ended June 30, 2010. The weighted average fair value of such restricted shares was $52.10 per share. There were no restricted share awards granted during the quarter ended June 30, 2010.

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Item 1. Financial Statements (Cont.)

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 nine months ended June 30, 2010. 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. Additionally, in February 2010, the FASB issued updated guidance that includes additional requirements and disclosures regarding fair value measurements. The guidance now requires the gross presentation of activity within the Level 3 roll forward and requires disclosure of details on transfers in and out of Level 1 and 2 fair value measurements. It also provides further clarification on the level of disaggregation of fair value measurements and disclosures on inputs and valuation techniques. The Company has updated its disclosures to reflect the new requirements in Note 2 Fair Value Measurements, except for the Level 3 roll forward gross presentation, which will be effective as of the Company s first quarter of fiscal 2012.

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 used to value oil and gas reserves with 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 will be 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 will be effective as of the Company s first quarter of fiscal 2011. Given the current organizational structure of the Company, the Company does not believe this authoritative guidance will have any impact on its consolidated financial statements.

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 table sets forth, by level within the fair value hierarchy, the Company s financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of June 30, 2010 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. In January 2010, the FASB issued amended authoritative guidance respecting disclosures related to fair value measurements. The amended guidance requires disclosure of financial instruments and liabilities by class of assets and liabilities (not major category of assets and liabilities). In addition, this amended guidance also requires enhanced disclosures about the valuation techniques and inputs used to measure fair value and disclosures of transfers in and out of Level 1 or 2. During the quarter ended March 31, 2010, the Company adopted this amended guidance.

Recurring Fair Value Measures	At fair value as of June 30, 2010			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Assets:				
Cash Equivalents Money Market Mutual Funds	$ 303,261	$	$	$ 303,261
Derivative Financial Instruments:				
Commodity Futures Contracts Gas	576			576
Over the Counter Swaps Oil		58	79	137
Over the Counter Swaps Gas		41,184		41,184
Other Investments:				
Balanced Equity Mutual Fund	15,805			15,805
Common Stock Financial Services Industry	5,762			5,762
Other Common Stock	201			201
Hedging Collateral Deposits (1)	8,222			8,222
Total	$ 333,827	$ 41,242	$ 79	$ 375,148
Liabilities:				
Derivative Financial Instruments:				
Commodity Futures Contracts Gas	$ 2,521	$	$	$ 2,521
Over the Counter Swaps Oil			225	225
Over the Counter Swaps Gas		30		30
Total	$ 2,521	$ 30	$ 225	$ 2,776
Total Net Assets/(Liabilities)	$ 331,306	$ 41,212	$ (146)	$ 372,372

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

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Item 1. Financial Statements (Cont.)

Recurring Fair Value Measures (Thousands of Dollars)	At fair value as of September 30, 2009 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
Total Net Assets/(Liabilities)	$ 420,898	$ 10,388	$ 26,969	$ 458,255

Derivative Financial Instruments

At June 30, 2010, 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 $6.4 million associated with these futures contracts have been reported in Level 1 as well. The derivative financial instruments 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 June 30, 2010 (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, discounted cash flow model that uses observable inputs (i.e. LIBOR based discount rates and basis differential information, if applicable, at active natural gas/crude oil trading markets). At June 30, 2010, 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). Hedging collateral deposits of $1.8 million associated with these oil swap agreements have been reported in Level 1. The fair value of the crude oil swap agreements is based on an internal, discounted cash flow model that uses both observable (i.e. LIBOR based discount rates) and unobservable inputs (i.e. basis differential information of crude oil trading markets with low trading volume). Based on an assessment of the counterparties credit risk, the fair market value of the price swap agreements reported as Level 2 and Level 3 assets have been reduced by $0.7 million and $0.9 million at June 30, 2010 and September 30, 2009, respectively. The fair market value of the price swap agreements reported as Level 2 liabilities at September 30, 2009 have been reduced by less than $0.1 million based on an assessment of the Company s credit risk. (Note: As the fair value of the price swap agreements reported as Level 2 and 3 liabilities at June 30, 2010 was minor and the hedging collateral sufficiently covered the liabilities, there was no credit reserve recorded for the Level 2 and 3 liabilities at June 30, 2010.) 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.

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 quarter and nine months ended June 30, 2010 and 2009, respectively. For the quarter ended June 30, 2010, no transfers in or out of Level 1 or Level 2 occurred.

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Item 1. Financial Statements (Cont.)

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)	March 31, 2010	Total Gains/Losses- Realized and Unrealized: Included in Earnings	Total Gains/Losses- Realized and Unrealized: Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	June 30, 2010
Derivative Financial Instruments(2)	$ (14,100)	$ (2,172)(1)	$ 16,126	$	$ (146)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended June 30, 2010.

(2) Derivative Financial Instruments are shown on a net basis.

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)	September 30, 2009	Total Gains/Losses- Realized and Unrealized: Included in Earnings	Total Gains/Losses- Realized and Unrealized: Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	June 30, 2010
Derivative Financial Instruments(2)	$ 26,969	$ (6,969)(1)	$ (20,146)	$	$ (146)

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

ended June 30, 2010.

(2) Derivative Financial Instruments are shown on a net basis.

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)	March 31, 2009	Total Gains/Losses- Realized and Unrealized: Included in Earnings	Total Gains/Losses- Realized and Unrealized: Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	June 30, 2009
Derivative Financial Instruments(2)	$ 79,159	$ (13,662)(1)	$ (22,459)	$ (8,492)	$ 34,546

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended June 30, 2009.

(2) Derivative Financial Instruments are shown on a net basis.

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)	September 30, 2008	Total Gains/Losses Realized and Unrealized: Included in Earnings	Total Gains/Losses Realized and Unrealized: Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	June 30, 2009
Derivative Financial Instruments(2)	$ 6,333	$ (49,443)(1)	$ 86,148	$ (8,492)	$ 34,546

(1) Amounts are reported in

Operating Revenues in the Consolidated Statement of Income for the nine months ended June 30, 2009.

(2) Derivative Financial Instruments are shown on a net basis.

Item 1. Financial Statements (Cont.)

Note 3 Financial Instruments

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

	June 30, 2010		September 30, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$ 1,249,000	$ 1,372,413	$ 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 $54.6 million at June 30, 2010 and $54.2 million at September 30, 2009. The fair value of the equity mutual fund was $15.8 million at June 30, 2010 and September 30, 2009. The gross unrealized loss on this equity mutual fund was $1.4 million at June 30, 2010 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 $5.8 million at June 30, 2010 and $8.3 million at September 30, 2009. The gross unrealized gain on this stock was $3.4 million at June 30, 2010 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 risk associated with forecasted gas purchases, storage of gas, withdrawal of gas from storage to meet customer demand, and the potential decline in the value of gas held in storage. The duration of the Company s hedges do not typically exceed 3 years.

The Company has presented its net derivative assets and liabilities on its Consolidated Balance Sheets at June 30, 2010 and September 30, 2009 as shown in the table below.

Fair Values of Derivative Instruments
(Thousands of Dollars)

Derivatives Designated as Hedging Instruments	**Asset Derivatives**		**Liability Derivatives**	
	Consolidated Balance Sheet Location	**Fair Value**	**Consolidated Balance Sheet Location**	**Fair Value**
Commodity Contracts at June 30, 2010	Fair Value of Derivative Financial Instruments	$41,897	Fair Value of Derivative Financial Instruments	$2,776
Commodity Contracts at September 30, 2009	Fair Value of Derivative Financial Instruments	$44,817	Fair Value of Derivative Financial Instruments	$2,148

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Item 1. Financial Statements (Cont.)

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 June 30, 2010 and September 30, 2009.

Derivatives Designated as Hedging Instruments		Fair Values of Derivative Instruments (Thousands of Dollars)	
		Gross Asset Derivatives Fair Value	Gross Liability Derivatives Fair Value
Commodity Contracts	at June 30, 2010	$ 52,984	$ 13,863
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 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.

At June 30, 2010, the Company s Exploration and Production segment had the following commodity derivative contracts (swaps) outstanding to hedge forecasted sales (where the Company uses short positions (i.e. positions that pay-off in the event of commodity price decline) to mitigate the risk of decreasing revenues and earnings):

Commodity	Units
Natural Gas	41.4 Bcf (all short positions)
Crude Oil	2,803,000 Bbls (all short positions)

At June 30, 2010, 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	4.8 Bcf (4.5 Bcf short positions (forecasted storage withdrawals) and 0.3 Bcf long positions (forecasted storage injections))

At June 30, 2010, the Company s Pipeline and Storage segment had 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	1.5 Bcf (all short positions)

Item 1. Financial Statements (Cont.)

At June 30, 2010, the Company s Exploration and Production segment had $39.9 million ($23.5 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $26.1 million ($15.4 million after tax) of those gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the expected sales of the underlying commodities occur. See Note 1, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain pertaining to derivative financial instruments (Net Unrealized Gain (Loss) on Derivative Financial Instruments in Note 1 includes the Exploration and Production, Energy Marketing and Pipeline and Storage segments).

At June 30, 2010, the Company s Energy Marketing segment had $1.4 million ($0.8 million after tax) of net hedging gains included in the accumulated other comprehensive income (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 and purchases of the underlying commodities occur. See Note 1, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain pertaining to derivative financial instruments (Net Unrealized Gain (Loss) on Derivative Financial Instruments in Note 1 includes the Exploration and Production, Energy Marketing and Pipeline and Storage segments).

At June 30, 2010, the Company s Pipeline and Storage segment had $0.1 million (less than $0.1 million after tax) of net hedging gains included in the accumulated other comprehensive income (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 expected sales of the underlying commodities occur. See Note 1, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain pertaining to derivative financial instruments (Net Unrealized Gain (Loss) on Derivative Financial Instruments in Note 1 includes the Exploration and Production, Energy Marketing and Pipeline and Storage segments).

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Item 1. Financial Statements (Cont.)

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended June 30, 2010 and 2009 (Thousands of Dollars)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Three Months Ended June 30,		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 June 30,		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 June 30,	
	2010	2009		2010	2009		2010	2009
Commodity Contracts Exploration & Production segment	$ 16,445	$ (23,013)	Operating Revenue	$ 11,592	$ 22,940	Operating Revenue	$	$ 158
Commodity Contracts Energy Marketing segment	$ 519	$ (1,433)	Purchased Gas	$ 238	$ 1,913	Operating Revenue	$	$
Commodity Contracts Pipeline & Storage segment	$ (436)	$	Operating Revenue	$	$	Operating Revenue	$	$
Total	$ 16,528	$ (24,446)		$ 11,830	$ 24,853		$	$ 158

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Item 1. Financial Statements (Cont.)

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Nine Months Ended June 30, 2010 and 2009 (Thousands of Dollars)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Nine Months Ended June 30, 2010	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 Nine Months Ended June 30, 2010	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 Nine Months Ended June 30, 2010	2009
Commodity Contracts Exploration & Production segment	$ 32,910	$ 117,764	Operating Revenue	$ 29,170	$ 71,324	Operating Revenue	$	$ 424
Commodity Contracts Energy Marketing segment	$ 5,821	$ 9,410	Purchased Gas	$ (209)	$ 21,328	Operating Revenue	$	$
Commodity Contracts Pipeline & Storage segment	$ 577	$	Operating Revenue	$ 511	$ 1,290	Operating Revenue	$	$
Commodity Contracts All Other[(1)]	$	$ 183	Purchased Gas	$	$ (682)	Purchased Gas	$	$

Total	$ 39,308	$ 127,357	$ 29,472	$ 93,260	$	$ 424

(1) There were no open hedging positions at June 30, 2010. As such there is no mention of these positions in the preceeding sections of this footnote.

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Item 1. Financial Statements (Cont.)

Fair value hedges

The Company s Energy Marketing segment utilizes fair value hedges to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in the value of natural gas held in storage. With respect to fixed price sales commitments, the Company enters into long positions to mitigate the risk of price increases for natural gas supplies that could occur after the Company enters into fixed price sales agreements with its customers. With respect to fixed price purchase commitments, the Company enters into short positions to mitigate the risk of price decreases that could occur after the Company locks into fixed price purchase deals with its suppliers. With respect to storage hedges, the Company enters into short positions to mitigate the risk of price decreases that could result in a lower of cost or market writedown of the value of natural gas in storage that is recorded in the Company s financial statements. As of June 30, 2010, the Company s Energy Marketing segment had fair value hedges covering approximately 10.8 Bcf (9.3 Bcf of fixed price sales commitments (all long positions), 1.3 Bcf of fixed price purchase commitments (all short positions) and 0.2 Bcf of storage hedges (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	$ (892,512)	$ 892,512
Purchased Gas	$ (502,195)	$ 502,195

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 Nine Months Ended June 30, 2010 (In Thousands)
Commodity Contracts	Energy Marketing segment[1]	Operating Revenues	$ (893)
Commodity Contracts	Energy Marketing segment[2]	Purchased Gas	$ (456)
Commodity Contracts	Energy Marketing segment[3]	Purchased Gas	$ (46)
			$ (1,395)

(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 natural gas held in storage.

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company s counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with eleven counterparties of which ten of the eleven counterparties are in a net gain position. On average, the Company had $4.1 million of credit exposure per counterparty in a gain position at June 30, 2010. BP Energy Company (an affiliate of BP Corporation North America, Inc.) was one of the ten counterparties in a gain position. At June 30, 2010, the Company had a $7.2 million receivable with BP Energy Company. The Company considered the credit quality of BP Energy Company (as it does with all of its counterparties) in determining hedge effectiveness and believes the hedges remain effective. The Company had not received any collateral from these counterparties at June 30, 2010 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.

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Item 1. Financial Statements (Cont.)

As of June 30, 2010, nine of the eleven counterparties to the Company s outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk related contingency feature. In the event the Company s credit rating increases or falls below a certain threshold (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 June 30, 2010, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $27.1 million according to the Company s internal model (discussed in Note 2 Fair Value Measurements). At June 30, 2010, the fair market value of the derivative financial instrument liability with a credit-risk related contingency feature was $0.3 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, which are in a liability position, the Company was required to post $1.8 million in hedging collateral deposits at June 30, 2010. This is discussed in Note 1 under Hedging Collateral Deposits.

For its exchange traded futures contracts which are in a liability position, the Company had posted $5.8 million in hedging collateral, and for its exchange traded futures contracts which are in an asset position, the Company had posted $0.6 million in hedging collateral as of June 30, 2010. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions and margin requirements it has with its counterparties.

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

Note 4 Income Taxes

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

	Nine Months Ended June 30,	
	2010	2009

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Item 1. Financial Statements (Cont.)

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

	Nine Months Ended June 30, 2010	Nine Months Ended June 30, 2009
U.S. Income Before Income Taxes	$ 303,039	$ 108,747
Income Tax Expense, Computed at Federal Statutory Rate of 35%	$ 106,064	$ 38,061
Increase (Reduction) in Taxes Resulting From:		
State Income Taxes	15,371	4,605
Domestic Production Activities Deduction	(711)	(1,790)
Miscellaneous	(5,197)	(5,839)
Total Income Taxes	$ 115,527	$ 35,037

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

	At June 30, 2010	At September 30, 2009
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 781,581	$ 733,581
Pension and Other Post-Retirement Benefit Costs	177,124	178,440
Other	55,716	54,977
Total Deferred Tax Liabilities	1,014,421	966,998
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(214,161)	(212,299)
Other	(97,595)	(144,686)
Total Deferred Tax Assets	(311,756)	(356,985)
Total Net Deferred Income Taxes	$ 702,665	$ 610,013
Presented as Follows:		
Net Deferred Tax Liability/(Asset) Current	$ (32,893)	$ (53,863)
Net Deferred Tax Liability Non-Current	735,558	663,876
Total Net Deferred Income Taxes	$ 702,665	$ 610,013

During the quarter ended March 31, 2010, the Company reduced its deferred tax asset relating to the Medicare Part D subsidy by $30 million to reflect changes made by the fundamental health care reform legislation enacted during that quarter. In conjunction with the reduction of the deferred tax asset, the Company reduced its Medicare Part D regulatory liability by $30 million. In the Company s Utility and Pipeline and Storage segments, the Company s post-retirement benefit plans are funded by a component of tariff rates charged to customers. As such, prior to the fundamental health care reform legislation, the $30 million tax benefit had been recorded as a regulatory liability in anticipation of flowing that tax benefit back to customers through adjusted tariff rates.

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 June 30, 2010 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 both June 30, 2010 and September 30, 2009.

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Item 1. Financial Statements (Cont.)

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 and fiscal 2010 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 2007 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.

As of June 30, 2010, the Company had a federal net operating loss carryover of $21.2 million. 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.

Note 5 Capitalization

Common Stock. During the nine months ended June 30, 2010, the Company issued 1,714,768 original issue shares of common stock as a result of stock option exercises and 4,000 original issue shares for restricted stock awards (non-vested stock as defined by the current accounting literature for stock-based compensation). The Company also issued 10,089 original issue shares of common stock to the 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 nine months ended June 30, 2010. 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 nine months ended June 30, 2010, 263,455 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 June 30, 2010 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 $14.8 million.

At June 30, 2010, 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 $17.5 million to $21.7 million. The minimum estimated liability of $17.5 million, which includes the $14.8 million discussed above, has been recorded on the Consolidated Balance Sheet at June 30, 2010. The Company expects to recover these environmental clean-up costs through rate recovery.

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Item 1. Financial Statements (Cont.)

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

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 June 30, 2010 (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	$ 126,326	$ 32,086	$ 112,802	$ 72,830	$ 344,044	$ 9,859	$ 224	$ 354,127
Intersegment Revenues	$ 2,653	$ 19,466	$	$	$ 22,119	$ 1,418	$ (23,537)	$
Segment Profit: Net Income (Loss)	$ 5,969	$ 7,234	$ 27,883	$ 1,411	$ 42,497	$ 186	$ (98)	$ 42,585

Nine Months Ended June 30, 2010 (Thousands)

Utility	Exploration and Production	Total Reportable Segments	Corporate and Intersegment Eliminations

		Pipeline and Storage		Energy Marketing		All Other		Total Consolidated
Revenue from External Customers	$ 707,323	$ 107,560	$ 328,312	$ 303,103	$ 1,446,298	$ 35,568	$ 652	$ 1,482,518
Intersegment Revenues	$ 13,315	$ 60,289	$	$	$ 73,604	$ 1,418	$ (75,022)	$
Segment Profit: Net Income (Loss)	$ 62,254	$ 30,036	$ 85,046	$ 8,472	$ 185,808	$ 2,925	$ (1,221)	$ 187,512

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Item 1. Financial Statements (Cont.)
Quarter Ended June 30, 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	$ 158,310	$ 30,791	$ 97,619	$ 71,894	$ 358,614	$ 8,269	$ 228	$ 367,111
Intersegment Revenues	$ 2,940	$ 20,033	$	$	$ 22,973	$ 374	$ (23,347)	$
Segment Profit: Net Income (Loss)	$ 5,396	$ 9,221	$ 27,083	$ 1,331	$ 43,031	$ (1,086)	$ 959	$ 42,904

Nine Months Ended June 30, 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	$ 1,009,962	$ 105,904	$ 281,410	$ 350,445	$ 1,747,721	$ 30,523	$ 675	$ 1,778,919
Intersegment Revenues	$ 13,339	$ 62,026	$	$	$ 75,365	$ 3,890	$ (79,255)	$
Segment Profit: Net Income (Loss)	$ 60,303	$ 41,582	$ (38,366)	$ 7,509	$ 71,028	$ (46)	$ 2,728	$ 73,710

Note 8 Intangible Assets

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

	At June 30, 2010	At September 30, 2009

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Net Carrying Amount

The gross carrying amount of intangible assets subject to amortization at June 30, 2010 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 $0.1 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 $0.4 million for the remainder of 2010 and $1.4 million annually for 2011, 2012, 2013 and 2014.

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Item 1. Financial Statements (Cont.)
Note 9 Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

Three months ended June 30,

	Retirement Plan		Other Post-Retirement Benefits	
	2010	2009	2010	2009
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)	(6,583)	(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]	(920)	2,255	(569)	3,878
Net Periodic Benefit Cost	$ 4,395	$ 3,805	$ 6,355	$ 6,415

Nine months ended June 30,

	Retirement Plan		Other Post-Retirement Benefits	
	2010	2009	2010	2009
Service Cost	$ 9,747	$ 8,185	$ 3,224	$ 2,851
Interest Cost	33,231	35,127	18,763	20,624
Expected Return on Plan Assets	(43,756)	(43,468)	(19,751)	(23,711)
Amortization of Prior Service Cost	492	548	(1,282)	(805)
Amortization of Transition Amount			405	1,699
Amortization of Losses	16,230	4,257	19,411	6,953
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [1]	2,896	12,853	2,919	16,232
Net Periodic Benefit Cost	$ 18,840	$ 17,502	$ 23,689	$ 23,843

(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.

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 nine months ended June 30, 2009 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 nine months ended June 30, 2009 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.

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Item 1. Financial Statements (Cont.)

Employer Contributions. During the nine months ended June 30, 2010, the Company contributed $20.2 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $21.4 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 approximately $4.1 million to its VEBA trusts and 401(h) accounts.

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

OVERVIEW

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

The Company is a diversified energy holding company that owns a number of subsidiary operating companies, and reports financial results in four reportable business segments. For the quarter ended June 30, 2010 compared to the quarter ended June 30, 2009, the Company experienced a decrease in earnings of $0.3 million, primarily due to lower earnings in the Pipeline and Storage segment. For the nine months ended June 30, 2010 compared to the nine months ended June 30, 2009, the Company experienced an increase in earnings of $113.8 million. The earnings increase for the nine-month period was driven largely by an impairment charge of $182.8 million ($108.2 million after tax) recorded in the Exploration and Production segment during the nine months ended June 30, 2009 that did not recur during the nine months ended June 30, 2010. In the Company s Exploration and Production segment, oil and gas property acquisitions, and 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 June 30, 2010 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.

The Company continues to focus on the development of its Marcellus Shale acreage in the Appalachian region of its Exploration and Production segment. The Marcellus Shale is a Middle Devonian-age geological shale formation that is present, nearly a mile or more below the surface, in the Appalachian region of the United States, including much of Pennsylvania and southern New York. Due to the depth at which this formation is found, drilling and completion costs, including the drilling and completion of horizontal wells with hydraulic fracturing, are very expensive. However, independent geological studies have indicated that this formation could yield natural gas reserves measured in the trillions of cubic feet. The Company owns approximately 738,000 net acres within the Marcellus Shale area and anticipates a significant increase in its reserve base from development in the Marcellus Shale. With this in mind, and with a natural desire to realize the value of these assets in a responsible and orderly fashion, the Company has spent significant amounts in this region. For the nine months ended June 30, 2010, the Company spent $217.6 million towards the development of the Marcellus Shale. This included paying $71.8 million in March 2010 for two tracts of leasehold acreage in Tioga and Potter Counties in Pennsylvania. The Company acquired these tracts, consisting of approximately 18,000 net acres, in order to expand its holdings of Marcellus Shale acreage. These tracts are geologically and geographically similar to the Company s existing Marcellus Shale acreage in the area, and will help the Company continue its developmental drilling program.

Coincident with the development of its Marcellus Shale acreage, the Company is building pipeline gathering and transmission facilities to connect Marcellus Shale production with existing pipelines in the region and is pursuing the development of additional pipeline and storage capacity in order to meet anticipated demand for the large amount of Marcellus Shale production expected to come on-line in the months and years to come. Two of these projects, the Tioga County Extension Project and the Northern Access expansion project, are considered significant for Empire and Supply Corporation. Both projects are designed to receive natural gas produced from the Marcellus Shale and transport it to Canada and the Northeast United States to meet growing demand in those areas. During the past year, Empire and Supply Corporation have experienced a decline in the volumes of natural gas received at the Canada/United States border at the Niagara River to be shipped across their systems. The historical price advantage for gas sold at the Niagara import points has declined as production in the Canadian producing regions has declined or been diverted to other demand areas, and as production from new shale plays has increased in the United States. These factors have been causing shippers to seek alternative gas supplies and consequently alternative transportation routes. Empire and Supply Corporation have seen transportation volumes decrease as a result of this situation. The Tioga County Extension Project and the Northern Access expansion project are designed to provide an alternative gas supply source for the customers of Empire and Supply Corporation. These projects, which are discussed more completely in the Investing Cash Flow section that follows, also will involve significant capital expenditures.

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

From a capital resources perspective, the Company has been able to meet its capital expenditure needs for all of the above projects by using cash from operations. The Company had $458.8 million in Cash and Temporary Cash Investments at June 30, 2010, as shown on the Company s Consolidated Balance Sheet. For the remainder of 2010, the Company expects that it will be able to use cash on hand and cash from operations as its first means of financing capital expenditures, with short-term borrowings being its next source of funding. It is not expected that long-term financing will be required to meet capital expenditure needs until 2011.

The possibility of environmental risks associated with a well completion technology referred to as hydraulic fracturing continues to be debated. In Pennsylvania, where the Company is focusing its Marcellus Shale development efforts, the permitting and regulatory processes seem to strike a balance between the environmental concerns associated with hydraulic fracturing and the benefits of increased natural gas production. Hydraulic fracturing is a well stimulation technique that has been used for many years, and in the Company s experience, one that the Company believes has little impact to the environment. Nonetheless, the potential for increased state or federal regulation of hydraulic fracturing could impact future costs of drilling in the Marcellus Shale and lead to operational delays or restrictions. There is also the risk that drilling could be prohibited on certain acreage that is prospective for the Marcellus Shale. For example, New York State currently has a moratorium on hydraulic fracturing of new horizontal wells in the Marcellus Shale. However, due to the small amount of Marcellus Shale acreage owned by the Company in New York State, the moratorium is not expected to have a significant impact on the Company s plans for Marcellus Shale development. Please refer to the Risk Factors section of the Form 10-K for the year ended September 30, 2009 as well as updates to that section in both the Form 10-Q for the quarter ended December 31, 2009 and the Form 10-Q for the quarter ended March 31, 2010 for further discussion.

On July 16, 2010, the Company entered into an Asset Purchase and Sale Agreement whereby the Company intends to sell its sawmill in Marienville, Pennsylvania and approximately 40 million board feet of logs, lumber and timber consisting of yard inventory along with unexpired timber cutting contracts and certain land and timber holdings designed to provide the purchaser with a supply of logs for the mill. Despite this sale, the Company intends to retain substantially all of its land and timber holdings, along with mineral rights on land to be sold. The Company will maintain a forestry operation, however, as part of this change in focus, the Company will no longer be processing lumber products. At closing, which is expected to occur in September 2010, the Company estimates receiving proceeds of approximately $15 million. In addition, the purchaser will assume approximately $7 million in payment obligations under the Company s timber cutting contracts with various timber suppliers. The aforementioned supply of logs is expected to occur over a five-year period, during which time the Company anticipates receiving up to an additional $10 million in proceeds. The Company does not anticipate a material impact to earnings from this sale.

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 and Item 2 of the Company s December 31, 2009 and March 31, 2010 Form 10-Qs. There have been no material changes to those disclosures other than as set forth below. The information presented below is an update of, and should be read in conjunction with, the critical accounting estimates in those documents.

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 exceeds the ceiling, a non-cash impairment charge must be recorded to reduce the book value of the oil and gas properties to the calculated ceiling. At June 30, 2010, the ceiling exceeded the book value of the oil and gas properties by approximately $231 million. The quoted Cushing, Oklahoma spot price for West Texas Intermediate oil at June 30, 2010 was $75.59 per Bbl. The quoted Henry Hub spot price for natural gas at June 30, 2010 was $4.68 per MMBtu. (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

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)
ceiling, rather than the Cushing oil and Henry Hub natural gas prices, which are only indicative of current prices.) If natural gas prices used in the ceiling test calculation at June 30, 2010 had been $1 per MMBtu lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $168 million. If crude oil prices used in the ceiling test calculation at June 30, 2010 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $183 million. If both natural gas and crude oil prices used in the ceiling test calculation at June 30, 2010 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 $120 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 s earnings were $42.6 million for the quarter ended June 30, 2010 compared to earnings of $42.9 million for the quarter ended June 30, 2009. The decrease in earnings of $0.3 million is a result of lower earnings in the Pipeline and Storage segment and a loss in the Corporate category. Higher earnings in the Exploration and Production, Utility and Energy Marketing segments and the All Other category partially offset these decreases.

The Company s earnings were $187.5 million for the nine months ended June 30, 2010 compared to earnings of $73.7 million for the nine months ended June 30, 2009. The increase in earnings of $113.8 million is primarily the result of higher earnings in the Exploration and Production segment. The Utility and Energy Marketing segments, as well as the All Other category, also contributed to the increase in earnings. Lower earnings in the Pipeline and Storage segment and a loss in the Corporate category slightly offset these increases. The Company s earnings for the nine months ended June 30, 2009 includes a non-cash $182.8 million impairment charge ($108.2 million after tax) recorded during the quarter ended December 31, 2008 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 June 30,			Nine Months Ended June 30,		
(Thousands)	2010	2009	Increase (Decrease)	2010	2009	Increase (Decrease)
Utility	$ 5,969	$ 5,396	$ 573	$ 62,254	$ 60,303	$ 1,951
Pipeline and Storage	7,234	9,221	(1,987)	30,036	41,582	(11,546)
Exploration and Production	27,883	27,083	800	85,046	(38,366)	123,412
Energy Marketing	1,411	1,331	80	8,472	7,509	963
Total Reportable Segments	42,497	43,031	(534)	185,808	71,028	114,780
All Other	186	(1,086)	1,272	2,925	(46)	2,971
Corporate	(98)	959	(1,057)	(1,221)	2,728	(3,949)
Total Consolidated	$ 42,585	$ 42,904	$ (319)	$ 187,512	$ 73,710	$ 113,802

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

(Thousands)	Three Months Ended June 30, 2010	2009	Increase (Decrease)	Nine Months Ended June 30, 2010	2009	Increase (Decrease)
Retail Sales Revenues:						
Residential	$ 88,158	$ 119,746	$ (31,588)	$ 521,202	$ 786,170	$ (264,968)
Commercial	10,721	15,627	(4,906)	73,438	122,197	(48,759)
Industrial	696	808	(112)	4,579	6,835	(2,256)
	99,575	136,181	(36,606)	599,219	915,202	(315,983)
Transportation	20,909	22,012	(1,103)	92,112	94,951	(2,839)
Off-System Sales	5,486		5,486	20,491	3,740	16,751
Other	3,009	3,057	(48)	8,816	9,408	(592)
	$ 128,979	$ 161,250	$ (32,271)	$ 720,638	$ 1,023,301	$ (302,663)

Utility Throughput

(MMcf)	Three Months Ended June 30, 2010	2009	Increase (Decrease)	Nine Months Ended June 30, 2010	2009	Increase (Decrease)
Retail Sales:						
Residential	7,055	8,468	(1,413)	50,292	55,001	(4,709)
Commercial	920	1,221	(301)	7,666	8,984	(1,318)
Industrial	66	55	11	512	499	13
	8,041	9,744	(1,703)	58,470	64,484	(6,014)
Transportation	10,530	10,747	(217)	51,957	52,476	(519)
Off-System Sales	1,124		1,124	4,034	513	3,521
	19,695	20,491	(796)	114,461	117,473	(3,012)

Degree Days

Three Months Ended June 30	Normal	2010	2009	Percent Colder (Warmer) Than Normal (1)	Percent Colder (Warmer) Than Prior Year (1)
Buffalo	927	665	854	(28.3)	(22.1)
Erie	885	631	821	(28.7)	(23.1)
Nine Months Ended June 30					
Buffalo	6,514	6,152	6,558	(5.6)	(6.2)
Erie	6,108	5,842	6,064	(4.4)	(3.7)

(1) Percents compare actual 2010 degree days to normal degree days and actual 2010 degree days to actual 2009 degree days.

2010 Compared with 2009

Operating revenues for the Utility segment decreased $32.3 million for the quarter ended June 30, 2010 as compared with the quarter ended June 30, 2009. This decrease largely resulted from a $36.6 million decrease in retail gas sales revenues and a $1.1 million decrease in transportation revenues, partially offset by a $5.5 million increase in off-system sales revenues. The decrease in retail gas sales revenues of $36.6 million was largely a function of warmer weather and slightly lower gas costs (subject to certain timing variations, gas costs are recovered dollar for dollar in revenues). The recovery of lower gas costs resulted from a lower cost of purchased gas combined with the refunding of previously over-recovered purchased gas

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costs. The Utility segment s average cost of purchased gas, including the cost of transportation and storage, was $6.70 per Mcf for the quarter ended June 30, 2010, a decrease of 2.6% from the average cost of $6.88 per Mcf for the quarter ended June 30, 2009. The decrease in transportation revenues of $1.1 million was primarily due to a 0.2 Bcf decrease in transportation throughput, largely the result of warmer weather.

The increase in off-system sales revenues of $5.5 million was largely due to the Utility segment not engaging in off-system sales from November 2008 through October 2009. This was due to Order No. 717 (Final Rule), which was issued by the FERC on October 16, 2008. The Final Rule seemingly held that a local distribution company making off-system sales on unaffiliated pipelines would be engaging in marketing that would require compliance with the FERC s standards of conduct. Accordingly, pending clarification of this issue from the FERC, as of November 1, 2008, Distribution Corporation ceased off-system sales activities. On October 15, 2009, the FERC released Order No. 717-A, which clarified that a local distribution company making off-system sales of gas that has been transported on non-affiliated pipelines is not subject to the FERC standards of conduct. In light of and in reliance on this clarification, Distribution Corporation determined that it could resume engaging in off-system sales on non-affiliated pipelines. Such off-system sales resumed in November 2009. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there was not a material impact to earnings.

Operating revenues for the Utility segment decreased $302.7 million for the nine months ended June 30, 2010 as compared with the nine months ended June 30, 2009. This decrease largely resulted from a $316.0 million decrease in retail gas sales revenues and a $2.8 million decrease in transportation revenues, partially offset by a $16.8 million increase in off-system sales revenues. The decrease in retail gas sales revenues of $316.0 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 lower cost of purchased gas combined with the refunding of previously over-recovered purchased gas costs. The Utility segment s average cost of purchased gas, including the cost of transportation and storage, was $7.16 per Mcf for the nine months ended June 30, 2010, a decrease of 16.1% from the average cost of $8.53 per Mcf for the nine months ended June 30, 2009. The decrease in transportation revenues of $2.8 million was primarily due to a 0.5 Bcf decrease in transportation throughput, largely the result of warmer weather. The increase in off-system sales revenues of $16.8 million was attributable to the reasons discussed above. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there was not a material impact to earnings.

The Utility segment s earnings for the quarter ended June 30, 2010 were $6.0 million, an increase of $0.6 million when compared with earnings of $5.4 million for the quarter ended June 30, 2009.

In the New York jurisdiction, earnings increased $0.4 million. The positive earnings impact associated with lower interest expense ($0.9 million) and lower income tax expense of $0.2 million (due to a lower effective tax rate) were partially offset by higher operating expenses of $0.7 million (primarily due to higher personnel costs, partially offset by a decrease in bad debt expense due to lower gas costs). The decrease in interest expense was primarily due to a decrease in storage inventory carrying costs caused by a decline in the net storage inventory balances as well as a decline in interest rates.

In the Pennsylvania jurisdiction, earnings increased $0.2 million. The positive earnings impact associated with a decrease in income tax expense of $1.7 million (primarily relating to additional tax-deductible repairs) and lower operating expenses of $0.1 million (primarily a decrease in bad debt expense due to lower gas costs) was partially offset by the negative earnings impact of warmer weather ($0.9 million) and higher interest expense on deferred gas costs ($0.5 million), largely due to an over-recovery of gas costs during fiscal 2009 (due to a decline in gas prices during fiscal 2009).

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 June 30, 2010, the WNC preserved earnings of approximately $1.0 million, as weather was warmer than normal for the period. For the quarter ended June 30, 2009, the WNC preserved earnings of approximately $0.4 million, as weather was warmer than normal for the period.

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The Utility segment s earnings for the nine months ended June 30, 2010 were $62.3 million, an increase of $2.0 million when compared with earnings of $60.3 million for the nine months ended June 30, 2009.

In the New York jurisdiction, earnings decreased $0.1 million. The positive earnings impact associated with lower operating expenses of $0.5 million (primarily a decrease in bad debt expense due to lower gas costs) and lower income tax expense of $0.4 million (due to a lower effective tax rate) were more than offset by an increase in interest expense ($0.5 million) and routine regulatory true-up adjustments ($0.9 million).

In the Pennsylvania jurisdiction, earnings increased $2.1 million. The positive earnings impact associated with a decrease in income tax expense of $5.0 million (primarily relating to additional tax-deductible repairs) and lower operating expenses of $3.2 million (primarily a decrease in bad debt expense due to lower gas costs) were the main factors in the earnings increase. These factors were partially offset by lower usage per account ($2.1 million), warmer weather ($0.9 million), routine regulatory true-up adjustments ($0.2 million), and higher interest expense ($2.3 million). The phrase usage per account refers to average gas consumption per account after factoring out any impact that weather may have had on consumption. The increase in interest expense was partially due to the Company s April 2009 debt issuance that was issued at a significantly higher interest rate than the debt that had matured in March 2009. In addition, accrued interest on deferred gas costs increased as a result of an over-recovery of gas costs during fiscal 2009 (due to a decline in gas prices during fiscal 2009).

For the nine months ended June 30, 2010, the WNC in the New York jurisdiction preserved earnings of approximately $1.3 million, as weather was warmer than normal. For the nine months ended June 30, 2009, the WNC reduced earnings by approximately $0.2 million, as weather was colder than normal.

Pipeline and Storage

Pipeline and Storage Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2010	2009	Increase (Decrease)	2010	2009	Increase (Decrease)
Firm Transportation	$ 32,205	$ 32,894	$ (689)	$ 106,926	$ 105,931	$ 995
Interruptible Transportation	618	635	(17)	1,458	2,862	(1,404)
	32,823	33,529	(706)	108,384	108,793	(409)
Firm Storage Service	16,646	16,648	(2)	50,032	50,101	(69)
Interruptible Storage Service	19	4	15	78	18	60
Other	2,064	643	1,421	9,355	9,018	337
	$ 51,552	$ 50,824	$ 728	$ 167,849	$ 167,930	$ (81)

Pipeline and Storage Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2010	2009	Increase (Decrease)	2010	2009	Increase (Decrease)
Firm Transportation	52,448	60,798	(8,350)	245,233	296,524	(51,291)
Interruptible Transportation	1,016	501	515	3,575	3,375	200
	53,464	61,299	(7,835)	248,808	299,899	(51,091)

2010 Compared with 2009

Operating revenues for the Pipeline and Storage segment increased $0.7 million in the quarter ended June 30, 2010 as compared with the quarter ended June 30, 2009. The increase was primarily due to an increase in efficiency gas revenues ($1.0 million) reported as part of other revenues in the table above. This increase was primarily due to higher gas prices and higher efficiency gas volumes during the quarter ended

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June 30, 2010 as compared with the quarter ended June 30, 2009. 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 for 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 buyers on the open market. 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. This increase was partially offset by a decrease in transportation revenues of $0.7 million due to a reduction in the level of short-term contracts entered into by shippers quarter over quarter as such shippers utilized lower priced routes.

Operating revenues for the Pipeline and Storage segment for the nine months ended June 30, 2010 decreased $0.1 million as compared with the nine months ended June 30, 2009. The decrease was due to a decrease in interruptible transportation revenues of $1.4 million largely due to a decrease in the gathering rate under Supply Corporation s tariff. Offsetting the decrease was an increase in firm transportation revenues of $1.0 million. This increase was primarily the result of higher revenues from the Empire Connector, which was placed in service in December 2008, partially offset by shippers utilizing lower priced routes as discussed above. Also offsetting the decrease was an increase in efficiency gas revenues of $0.6 million due to higher efficiency gas volumes and the non-recurrence of an efficiency gas inventory write down which occurred during the nine months ended June 30, 2009. These increases to efficiency gas revenues were partially offset by lower gas prices and a lower gain, period over period, on the sale of retained efficiency gas volumes held in inventory.

Transportation volume for the quarter ended June 30, 2010 decreased by 7.8 Bcf from the prior year s quarter. For the nine months ended June 30, 2010, transportation volumes decreased by 51.1 Bcf from the prior year s nine-month period. These decreases were largely due to shippers seeking alternative lower priced gas supply (and in some cases, not renewing short-term transportation contracts) combined with warmer weather and lower industrial demand. The reason shippers are seeking lower priced gas supply is primarily because of the relatively higher price of Canadian natural gas supplies available at the United States/Canadian border at the Niagara River near Buffalo, New York compared to the lower pricing for domestic supplies. Empire s proposed Tioga County Extension Project and Supply Corporation s Northern Access expansion project, both of which are discussed in the Investing Cash Flow section that follows, are designed to utilize that available pipeline capacity by receiving natural gas produced from the Marcellus Shale and transporting it to Canada and the Northeast United States where demand has been growing. Much of the impact of lower volumes is offset by the straight fixed-variable rate design utilized by Supply Corporation and Empire. However, this rate design does not protect Supply Corporation or Empire in situations where shippers do not renew their existing contracts and new shippers do not contract for that capacity at the same quantity and rate. In that situation, Supply Corporation or Empire can propose revised rates and services in a rate case at the FERC.

The Pipeline and Storage segment s earnings for the quarter ended June 30, 2010 were $7.2 million, a decrease of $2.0 million when compared with earnings of $9.2 million for the quarter ended June 30, 2009. The earnings decrease was due to the earnings impact of lower transportation revenues of $0.5 million, as discussed above, combined with higher property taxes ($0.5 million), higher operating expenses ($1.1 million) and lower interest income ($0.3 million). The increase in property taxes is primarily a result of additional property taxes and higher payments in lieu of taxes associated with the Empire Connector. The increase in operating expenses can primarily be attributed to higher pension expense, higher personnel costs, the recording of gas losses related to one of Supply Corporation s storage wells and an increase in the reserve for preliminary project costs associated with Supply Corporation s West-to-East Overbeck to Leidy project. These operating expense increases (totaling $2.5 million) were partly offset by the reversal of reserves for preliminary project costs associated with Empire s Tioga County Extension Project and Supply Corporation s Line N Expansion Project (totaling $1.4 million) since the Company has determined that it is highly probable that the projects will be built. Refer to the Investing Cash Flow section that follows for further discussion of the reversal of these reserves. The reserve reversal also includes costs associated with the relocation of the existing Line N. The decline in interest income is a result of lower interest rates. The earnings decreases were partially offset by the earnings impact associated with higher efficiency gas revenue of $0.6 million, as discussed above.

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The Pipeline and Storage segment s earnings for the nine months ended June 30, 2010 were $30.0 million, a decrease of $11.6 million when compared with earnings of $41.6 million for the nine months ended June 30, 2009. The decrease in earnings is primarily due to a decrease in the allowance for funds used during construction ($2.8 million), higher operating costs ($3.3 million), higher property taxes ($1.6 million), higher interest expense ($3.2 million) and lower interest income ($0.5 million). Lower transportation revenues of $0.3 million, as discussed above, also contributed to the earnings decrease. The decrease in allowance for funds used during construction (equity component) is a result of the construction of the Empire Connector, which was completed and placed in service on December 10, 2008. The increase in operating expenses can primarily be attributed to higher pension expense, higher personnel costs, and an increase in the reserve for preliminary project costs associated with Supply Corporation s West-to-East Overbeck to Leidy project. The reversal of reserves for preliminary project costs associated with Empire s Tioga County Extension Project and Supply Corporation s Line N Expansion Project and relocation of Line N discussed above did not have a significant impact on earnings for the nine months ended June 30, 2010 as substantially all of the preliminary project costs related to the reserve reversals were incurred during the nine months ended June 30, 2010. The increase in property taxes is primarily a result of additional property taxes and higher payments in lieu of taxes associated with the Empire Connector. 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 decline in interest income is a result of lower cash balances and lower interest rates. The earnings decreases were partially offset by the earnings impact associated with higher efficiency gas revenue of $0.4 million, as discussed above.

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2010	2009	Increase (Decrease)	2010	2009	Increase (Decrease)
Gas (after Hedging)	$ 48,381	$ 38,450	$ 9,931	$ 135,761	$ 118,345	$ 17,416
Oil (after Hedging)	60,891	56,690	4,201	183,800	156,340	27,460
Gas Processing Plant	7,207	5,380	1,827	22,078	18,785	3,293
Other	218	270	(52)	380	717	(337)
Intrasegment Elimination (1)	(3,895)	(3,171)	(724)	(13,707)	(12,777)	(930)
	$ 112,802	$ 97,619	$ 15,183	$ 328,312	$ 281,410	$ 46,902

(1) Represents the elimination of certain West Coast gas production 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.

	Three Months Ended June 30,			Nine Months Ended June 30,		
Production Volumes	2010	2009	Increase (Decrease)	2010	2009	Increase (Decrease)
Gas Production *(MMcf)*						
Gulf Coast	2,745	3,307	(562)	8,079	7,118	961
West Coast	940	1,014	(74)	2,866	3,063	(197)
Appalachia	4,741	2,155	2,586	11,084	6,065	5,019
Total Production	8,426	6,476	1,950	22,029	16,246	5,783
Oil Production *(Mbbl)*						
Gulf Coast	135	176	(41)	389	470	(81)
West Coast	661	654	7	2,007	1,984	23
Appalachia	13	14	(1)	34	41	(7)
Total Production	809	844	(35)	2,430	2,495	(65)

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Average Prices

	Three Months Ended June 30, 2010	2009	Increase (Decrease)	Nine Months Ended June 30, 2010	2009	Increase (Decrease)
Average Gas Price/Mcf						
Gulf Coast	$ 4.95	$ 3.95	$ 1.00	$ 5.26	$ 4.90	$ 0.36
West Coast	$ 4.38	$ 3.04	$ 1.34	$ 4.92	$ 4.10	$ 0.82
Appalachia	$ 4.45	$ 4.11	$ 0.34	$ 5.10	$ 6.06	$ (0.96)
Weighted Average	$ 4.61	$ 3.86	$ 0.75	$ 5.13	$ 5.18	$ (0.05)
Weighted Average After Hedging	$ 5.74	$ 5.94	$ (0.20)	$ 6.16	$ 7.28	$ (1.12)
Average Oil Price/Bbl						
Gulf Coast	$ 76.42	$ 56.29	$ 20.13	$ 78.64	$ 50.64	$ 28.00
West Coast	$ 71.92	$ 55.77	$ 16.15	$ 71.79	$ 46.84	$ 24.95
Appalachia	$ 74.90	$ 48.93	$ 25.97	$ 77.77	$ 54.90	$ 22.87
Weighted Average	$ 72.72	$ 55.77	$ 16.95	$ 72.97	$ 47.69	$ 25.28
Weighted Average After Hedging	$ 75.23	$ 67.19	$ 8.04	$ 75.65	$ 62.67	$ 12.98

2010 Compared with 2009

Operating revenues for the Exploration and Production segment increased $15.2 million for the quarter ended June 30, 2010 as compared with the quarter ended June 30, 2009. Oil production revenue after hedging increased $4.2 million. An increase in the weighted average price of oil after hedging ($8.04 per Bbl) was the primary cause, as oil production levels were slightly lower quarter over quarter. Gas production revenue after hedging increased $9.9 million. An increase in Appalachian natural gas production was partially offset by lower Gulf Coast production and a $0.20 per Mcf decrease in the weighted average price of gas after hedging. The increase in Appalachian production was primarily due to higher production from Marcellus Shale wells. Production from existing Gulf Coast properties continued its general decline and there was no production from new fields during the quarter ended June 30, 2010 as compared to the quarter ended June 30, 2009 to offset that decline. The decline in Gulf Coast production reflects the Company s decision to de-emphasize Gulf Coast production and place more emphasis on Marcellus Shale production in the Appalachian region.

Operating revenues for the Exploration and Production segment increased $46.9 million for the nine months ended June 30, 2010 as compared with the nine months ended June 30, 2009. Oil production revenue after hedging increased $27.5 million. An increase in the weighted average price of oil after hedging ($12.98 per Bbl) was the primary cause, as oil production levels were slightly lower period over period. Gas production revenue after hedging increased $17.4 million. Increases in Gulf Coast and Appalachian production were partially offset by a $1.12 per Mcf decrease in the weighted average price of gas after hedging. The increase in Gulf Coast production resulted from a new discovery (Cyclops) that came on-line late in the quarter ended March 31, 2009, which more than offset the decline in production from existing fields. The increase in Appalachian production is mainly due to Marcellus Shale production that came on-line during the nine months ended June 30, 2010.

The Exploration and Production segment s earnings for the quarter ended June 30, 2010 were $27.9 million, an increase of $0.8 million when compared with earnings of $27.1 million for the quarter ended June 30, 2009. Higher crude oil prices and higher natural gas production increased earnings by $4.2 million and $7.5 million, respectively. In addition, higher processing plant revenues ($0.7 million) largely due to an increase in the commodity prices of residual gas and liquids sold at Seneca s processing plants in the West Coast region further contributed to an increase in earnings. Decreased interest expense ($0.4 million) due to the capitalization of interest on unproved properties (as a result of the Company s increased emphasis in developing assets in the Marcellus Shale) also contributed to the earnings increase. Lower crude oil production ($1.5 million) and lower natural gas prices ($1.1 million) partially offset the increase in earnings. In addition, the earnings increases noted above were mostly offset by higher depletion expense ($3.6 million), higher lease operating expenses ($3.1 million), the earnings impact associated with higher income tax

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expense ($1.7 million), and higher general and administrative and other operating expenses ($1.0 million). The increase in depletion expense was primarily due to an increase in production and depletable base (largely due to increased capital spending in the Appalachian region). The increase in lease operating expenses was largely due to higher steaming costs in California, additional production properties related to the acquisition of Ivanhoe Energy s United States oil and gas properties in July 2009, and an increase in the costs associated with a higher number of production properties in Appalachia. The increase in general and administrative and other operating expenses is mainly due to higher personnel costs (specifically in the Appalachian region).

The Exploration and Production segment s earnings for the nine months ended June 30, 2010 were $85.0 million, compared with a loss of $38.4 million for the nine months ended June 30, 2009, an increase of $123.4 million. The increase in earnings is primarily the result of the non-recurrence of an impairment charge of $108.2 million during the quarter ended December 31, 2008, as discussed in the Overview section above. Higher crude oil prices and higher natural gas production increased earnings by $20.5 million and $27.4 million, respectively. Higher processing plant revenues ($1.5 million) largely due to an increase in the commodity prices of residual gas and liquids sold at Seneca s processing plants in the West Coast region further contributed to an increase in earnings. In addition, lower interest expense ($1.6 million) due to a lower average amount of debt outstanding and the capitalization of interest, discussed above, further contributed to an increase in earnings. Lower crude oil production ($2.6 million) and lower natural gas prices ($16.1 million) partially offset the increase in earnings. In addition, the earnings increases noted above were partially offset by higher depletion expense ($7.5 million), higher lease operating expenses ($4.6 million), the earnings impact associated with higher income tax expense ($2.7 million), lower interest income ($1.1 million), and higher general and administrative and other operating expenses ($0.9 million). The increase in depletion expense was primarily due to an increase in production and depletable base (largely due to increased capital spending in the Appalachian region). The increase in lease operating expenses was largely due to higher steaming costs in California, additional production properties related to the acquisition of Ivanhoe Energy s United States oil and gas properties in July 2009, and an increase in the costs associated with a higher number of production properties in Appalachia. The decrease in interest income is primarily due to lower interest rates on cash investment balances. The increase in general and administrative and other operating expenses is mainly due to higher personnel costs (specifically in the Appalachian region).

Energy Marketing

Energy Marketing Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2010	2009	Increase	2010	2009	Increase (Decrease)
Natural Gas (after Hedging)	$ 72,759	$ 71,870	$ 889	$ 302,931	$ 350,331	$ (47,400)
Other	71	24	47	172	114	58
	$ 72,830	$ 71,894	$ 936	$ 303,103	$ 350,445	$ (47,342)

Energy Marketing Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2010	2009	Decrease	2010	2009	Increase
Natural Gas (MMcf)	13,047	14,634	(1,587)	51,144	50,459	685

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2010 Compared with 2009

Operating revenues for the Energy Marketing segment increased $0.9 million for the quarter ended June 30, 2010 as compared with the quarter ended June 30, 2009. The slight increase reflects an increase in gas sales revenue due to a higher average price of natural gas that was recovered through revenues. The decline in volume is largely attributable to fewer 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. Such transactions had the effect of increasing revenue and volume sold with minimal impact to earnings.

Operating revenues for the Energy Marketing segment decreased $47.3 million for the nine months ended June 30, 2010 as compared with the nine months ended June 30, 2009. The decrease primarily reflects a decline in gas sales revenue due to a lower average price of natural gas that was recovered through revenues. The increase in volume is largely 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. Such transactions had the effect of increasing revenue and volume sold with minimal impact to earnings.

The Energy Marketing segment s earnings for the quarter ended June 30, 2010 were $1.4 million, an increase of $0.1 million when compared with earnings of $1.3 million for the quarter ended June 30, 2009. The Energy Marketing segment s earnings for the nine months ended June 30, 2010 were $8.5 million, an increase of $1.0 million when compared with earnings of $7.5 million for the nine months ended June 30, 2009. These increases were partially attributable to higher margin of $0.5 million and $1.0 million for the quarter and nine-month periods, respectively. The increase in margin was primarily driven by improved average margins per Mcf as well as the marketing flexibility that the Energy Marketing segment derives from its contracts for storage capacity. Higher operating expenses of $0.3 million and $0.1 million for the quarter and nine-month periods, respectively, partially offset the increase in earnings. The increase in operating expenses for the quarter and nine months ended June 30, 2010 was primarily due to a June 2010 accrual for U.S. Customs merchandise processing fees that may be due for certain past gas imports from Canada. For the nine months ended June 30, 2010 as compared to the prior year s nine-month period, the increase in operating expenses was partly offset by lower bad debt expense.

Corporate and All Other
2010 Compared with 2009

Corporate and All Other recorded earnings of $0.1 million for the quarter ended June 30, 2010, an increase of $0.2 million when compared with losses of $0.1 million for the quarter ended June 30, 2009. The increase in earnings was due to higher margins of $3.0 million, which was mostly attributable to higher margins from log and lumber sales (partially due to the increase in timber harvested from low cost basis, Company owned lands) coupled with higher revenues from Midstream Corporation s pipeline and gathering operations. The increase was partially offset by higher income tax expense of $1.1 million (due to a higher effective tax rate), higher depreciation and depletion expense of $0.8 million (mostly attributable to increased depletion expense due to an increase in timber harvested from Company owned lands), and higher operating costs of $0.4 million (mostly attributable to an increase in Midstream Corporation s operating activities). Midstream Corporation was formed to build, own and operate natural gas processing and pipeline gathering facilities in the Appalachian region.

For the nine months ended June 30, 2010, Corporate and All Other had earnings of $1.7 million, a decrease of $1.0 million when compared with earnings of $2.7 million for the nine months ended June 30, 2009. The decrease in earnings was due to higher interest expense of $3.9 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), higher income tax expense of $3.6 million (due to a higher effective tax rate), higher depreciation and depletion expense of $1.6 million (mostly attributable to increased depletion expense due to an increase in timber harvested from Company owned lands), decreased earnings from unconsolidated subsidiaries of $0.6 million (due to the lower price of electricity sold by Seneca Energy (a subsidiary that generates electricity

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using methane gas obtained from landfills owned by outside parties)), and higher operating costs of $0.4 million (mostly attributable to an increase in Midstream Corporation s operating activities). In addition, the non-recurrence of a gain resulting from a death benefit on corporate-owned life insurance policies held by the Company of $2.3 million that occurred during the quarter ended December 31, 2008 further reduced earnings. The decreases were partially offset by higher margins of $6.5 million and higher interest income of $3.2 million. The increase in margins was mostly attributable to higher margins from log and lumber sales (partially due to the increase in timber harvested from low cost basis, Company owned lands) coupled with higher revenues from Midstream Corporation s pipeline and gathering operations. The increase in interest income was due to higher intercompany interest collected from the Company s other operating segments as a result of the allocation of the aforementioned April 2009 debt issuance to such segments. 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 impairment was $1.8 million ($1.1 million on an after tax basis).

Interest Income

Interest income was $0.9 million lower in the quarter ended June 30, 2010 as compared with the quarter ended June 30, 2009. For the nine months ended June 30, 2010, interest income decreased $2.3 million as compared with the nine months ended June 30, 2009. The impact of lower interest rates on cash investment balances more than offset the impact of higher cash investment balances.

Other Income

Other income decreased $0.7 million for the quarter ended June 30, 2010 as compared with the quarter ended June 30, 2009. This decrease is largely attributable to smaller quarter-over-quarter increases in the value of corporate-owned life insurance policies. For the nine months ended June 30, 2010, other income decreased $4.9 million as compared with the nine months ended June 30, 2009. This decrease is attributable to a $2.8 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 death benefit gain on corporate-owned life insurance policies of $2.3 million recognized during the first quarter of 2009 did not recur in 2010.

Interest Expense on Long-Term Debt

Interest expense on long-term debt decreased $0.6 million for the quarter ended June 30, 2010 as compared with the quarter ended June 30, 2009. For the nine months ended June 30, 2010, interest expense on long-term debt increased $7.9 million as compared with the nine months ended June 30, 2009. During fiscal 2009, the Exploration and Production segment significantly increased its capital expenditures related to unproved properties in the Marcellus Shale area of the Appalachian region. As a result, the Company capitalized interest costs associated with the capital expenditures, which decreased interest expense by $0.9 million. During the quarter ended June 30, 2010, this decrease more than offset the increase in interest expense as a result of a higher average amount of long-term debt outstanding combined with higher average interest rates. For the nine months ended June 30, 2010, the decrease in interest expense as a result of the aforementioned capitalized interest ($0.9 million) was more than offset by the increase in the 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 partly offset by the repayment of $100 million of 6.0% medium-term notes that matured in March 2009.

Other Interest Expense

Other Interest expense decreased $0.7 million for the quarter ended June 30, 2010 as compared with the quarter ended June 30, 2009. The decrease is mainly due to lower interest expense on regulatory deferrals (primarily deferred gas costs) in the Utility segment. For the nine months ended June 30, 2010, other interest expense increased $0.3 million as compared with the nine months ended June 30, 2009. The increase in interest expense is mainly attributed to a decrease in the allowance for borrowed funds used during construction resulting from the completion of the Empire Connector, which was partially offset by a decrease in interest expense on regulatory deferrals (primarily deferred gas costs) in the Utility segment.

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CAPITAL RESOURCES AND LIQUIDITY

The Company s primary source of cash during the nine-month period ended June 30, 2010 consisted of cash provided by operating activities. The Company s primary source of cash during the nine-month period ended June 30, 2009 consisted of cash provided by operating activities and proceeds from the issuance of long-term debt. These sources of cash were supplemented by issues of new shares of common stock as a result of stock option exercises for both the nine-month periods ended June 30, 2010 and June 30, 2009. During the nine months ended June 30, 2010 and June 30, 2009, 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.

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 partnerships, deferred income taxes, and income or loss from unconsolidated subsidiaries net of cash distributions.

Cash provided by operating activities in the Utility and the 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 $419.9 million for the nine months ended June 30, 2010, a decrease of $94.3 million compared with $514.2 million provided by operating activities for the nine months ended June 30, 2009. The decrease is primarily due to the timing of gas cost recovery in the Utility segment. As gas prices decreased significantly during 2009, the Company s Utility segment experienced an over-recovery of gas costs that was reflected in Amounts Payable to Customers on the Company s Consolidated Balance Sheet. Since September 30, 2009, the Company has been refunding that over-recovery to its customers. From a consolidated perspective, higher interest payments on long-term debt also contributed to the decrease in cash provided by operating activities.

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Investing Cash Flow

Expenditures for Long-Lived Assets

The Company s expenditures for long-lived assets totaled $342.0 million during the nine months ended June 30, 2010 and $232.9 million for the nine months ended June 30, 2009. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets

Nine Months Ended June 30, (Millions)	2010	2009	Increase (Decrease)
Utility	$ 39.5	$ 40.4	$ (0.9)
Pipeline and Storage	22.2	37.2(3)	(15.0)
Exploration and Production	273.8(1) (2)	151.7(4)	122.1
All Other	6.5(2)	3.9	2.6
Eliminations		(0.3) (5)	0.3
	$ 342.0	$ 232.9	$ 109.1

(1) Amount includes $24.3 million of accrued capital expenditures at June 30, 2010, the majority of which was in the Appalachian region. This amount has been excluded from the Consolidated Statement of Cash Flows at June 30, 2010 since it represents a non-cash investing activity at that date.

(2) Capital expenditures for the Exploration and Production segment for the nine months ended June 30,

2010 exclude $9.1 million of accrued capital expenditures, the majority of which was in the Appalachian region. Capital expenditures for All Other for the nine months ended June 30, 2010 exclude $0.7 million of accrued 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 nine months ended June 30, 2010. 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 June 30, 2010.

(3)

Amount for the nine months ended June 30, 2009 excludes $16.8 million of accrued capital expenditures related to the Empire Connector project accrued at September 30, 2008 and paid during the nine months ended June 30, 2009. 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 June 30, 2009.

(4) Amount for the nine months ended June 30, 2009 includes $9.4 million of accrued capital expenditures, the majority of which was in the Appalachian region. This amount has been excluded

from the Consolidated Statement of Cash Flows at June 30, 2009 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 nine months ended June 30, 2010 and June 30, 2009 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 nine months ended June 30, 2010 were related to additions, improvements, and replacements to this segment s transmission and gas storage systems. The Pipeline and Storage capital expenditure amounts for the nine months ended June 30, 2010 also include $5.8 million spent on the Lamont Project, discussed below. The majority of the Pipeline and Storage capital expenditures for the nine months ended June 30, 2009 were related to the Empire Connector project, which was placed into service on December 10, 2008, as well as additions, improvements, and replacements to this segment s transmission and gas storage systems.

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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 and paying for preliminary survey and investigation costs, which are initially recorded as Deferred Charges on the Consolidated Balance Sheet. An offsetting reserve is established as those preliminary survey and investigation costs are incurred, which reduces the Deferred Charges balance and increases Operation and Maintenance Expense on the Consolidated Statement of Income. The Company reviews all projects on a quarterly basis, and if it is determined that it is highly probable that the project will be built, the reserve is reversed. This reversal reduces Operation and Maintenance Expense and reestablishes the original balance in Deferred Charges. After the reversal of the reserve, amounts remain in Deferred Charges until construction begins, at which point the balance is transferred from Deferred Charges to Construction Work in Progress, a component of Property, Plant and Equipment on the Consolidated Balance Sheet.

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 (TETCO Holbrook) 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 September 2011. On October 20, 2009, the FERC granted Supply Corporation s request for a pre-filing environmental review of the Line N Expansion Project, and on June 11, 2010, Supply Corporation filed an NGA Section 7(c) application to the FERC for approval of the project. The preliminary cost estimate for the Line N Expansion Project is $23 million. As of June 30, 2010, approximately $0.4 million has been spent to study the Line N Expansion Project. The Company has determined that it is highly probable that this project will be built. Accordingly, all previous reserves have been reversed and the $0.4 million has been reestablished as a Deferred Charge on the Consolidated Balance Sheet. Supply Corporation has also executed a precedent agreement for an additional 150,000 Dth/day of capacity on Line N to TETCO Holbrook for service beginning November 2012 (Line N Phase II Expansion Project). The preliminary cost estimate for the Line N Phase II Expansion Project is approximately $30 million. As of June 30, 2010, no preliminary survey and investigation charges had been spent on this project.

The second strategic horsepower expansion project, involving the addition of compression at Supply Corporation s existing interconnect with Tennessee Gas Pipeline (TGP) at Lamont, Pennsylvania, was placed in-service on June 15, 2010 (Lamont Project). The Lamont Project, which is designed and contracted for 40,000 Dth/day of firm transportation, affords shippers a transportation path from their current and anticipated Marcellus production located in Elk and Cameron Counties, Pennsylvania to markets attached to TGP s 300 Line. The Lamont Project was constructed under Supply Corporation s existing blanket construction certificate authority from the FERC. The cost estimate for the Lamont Project is $6 million. As of June 30, 2010, approximately $5.8 million has been spent related to the Lamont Project, all of which has been capitalized as Property, Plant and Equipment at June 30, 2010. A second Lamont project phase is also being planned (Lamont Phase II Project). With the construction of additional horsepower, up to 50,000 Dth/day of incremental firm capacity could be available by July 2011. Supply Corporation has one signed precedent agreement for a portion of this capacity and is completing negotiations for a second agreement for the remainder. The preliminary cost estimate for the Lamont Phase II Project is approximately $7 million. As of June 30, 2010, no preliminary survey and investigation charges had been spent on the Lamont Phase II project.

Supply Corporation has also signed a binding precedent agreement to provide 320,000 Dth/day of firm transportation capacity in conjunction with its Northern Access expansion project. Upon satisfaction of the conditions in the precedent agreement, Statoil Natural Gas LLC will enter into a 20-year firm transportation agreement for 320,000 Dth/day. This capacity, which was offered and awarded in Supply Corporation s Open Season 159 that commenced January 12, 2010 and ended February 17, 2010, will provide the subscribing shipper with a firm transportation path from the Ellisburg area into the TransCanada Pipeline at Niagara. This path is attractive because it provides a route for Marcellus shale gas, principally

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along the TGP 300 Line in northern Pennsylvania, to be distributed from the Marcellus supply basin to northern markets. Service is expected to begin in late 2012, and Supply Corporation will shortly begin working on an application for FERC authorization of the project. The project facilities involve additional compression at Supply Corporation s existing interconnects with TGP at Ellisburg and at East Aurora, along with other system enhancements. The preliminary cost estimate for the Northern Access expansion is $60 million, substantially all of which is expected to be incurred in fiscal 2012. As of June 30, 2010, no preliminary survey and investigation charges had been spent on this project.

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. So, based on requests from the Marcellus producing community for transportation service, 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 ; together W2E Overbeck to Leidy) of the W2E pipeline project. As currently envisioned, the W2E Overbeck to Leidy project is designed to transport at least 425,000 Dth/day, and involves construction of a new 82-mile pipeline through Elk, Cameron, Clinton, Clearfield and Jefferson Counties to the Leidy Hub, from Marcellus and other producing areas along over 300 miles of Supply Corporation s existing pipeline system. The W2E Overbeck to Leidy project also includes a total of approximately 25,000 horsepower of compression at two separate stations. The project may be built in phases depending on the development of Marcellus production along the corridor, with the first facilities expected to go in service in 2013.

The binding Open Season for the W2E Overbeck to Leidy project concluded on October 8, 2009 with participation by several Marcellus producers. Supply Corporation received requests for 175,000 Dth/day of firm transportation capacity, and has executed binding precedent agreements to provide 125,000 Dth/day of firm transportation. Supply Corporation is pursuing post-Open Season capacity requests for the remaining capacity. On March 31, 2010, the FERC granted Supply Corporation s request for a pre-filing environmental review of the W2E Overbeck to Leidy project, and Supply Corporation is in the process of preparing an NGA Section 7(c) application. The capital cost of this project is estimated to be $260 million. As of June 30, 2010, approximately $2.7 million has been spent to study the W2E Overbeck to Leidy project, which has been included in preliminary survey and investigation charges and has been fully reserved for at June 30, 2010.

Supply Corporation has developed plans for new storage capacity by expansion of two of its existing storage facilities. The expansion of the East Branch and Galbraith fields, which could be completed in early 2013, will provide 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 could complement the W2E Overbeck to Leidy project by providing incremental transportation throughput to and from various market interconnect points. It could 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 would 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 June 30, 2010, 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 June 30, 2010. 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 the W2E Overbeck to Leidy project due to its strategic upstream location. The Appalachian Lateral pipeline, which would be 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 into the W2E Overbeck to Leidy facilities. Supply Corporation expects to continue marketing efforts for all remaining sections of the W2E/Appalachian Lateral project. The timeline and projected costs associated with sections other than W2E Overbeck to Leidy, including the Appalachian Lateral project, will depend on market development. As of June 30, 2010, no preliminary survey and investigation charges had been spent on the remaining sections of the

W2E/Appalachian Lateral project.

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On October 1, 2009, Empire commenced its Open Season 006 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 $47 million. This project would enable shippers to deliver their gas at existing Empire interconnections with Millennium Pipeline at Corning, New York, with the TransCanada Pipeline at the Niagara River at Chippawa, and with utility and power generation markets along its path, as well as to a planned new interconnection with TGP 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 signed binding precedent agreements with two shippers representing the total capacity of the project of 350,000 Dth/day. On January 28, 2010, the FERC granted Empire s request for a pre-filing environmental review of the Tioga County Extension Project, and Empire is in the process of preparing an NGA Section 7 (c) application to the FERC for approval of the project, which it expects to file this August. Empire anticipates that these facilities will be placed in-service on or after September 1, 2011. As of June 30, 2010, approximately $1.5 million has been spent to study the Tioga County Extension Project. The Company has determined that it is highly probable that this project will be built. Accordingly, all previous reserves have been reversed and the $1.5 million has been reestablished as a Deferred Charge on the Consolidated Balance Sheet.

The Company anticipates financing the Line N Expansion Projects, the Lamont Projects, the Northern Access expansion project, the W2E Overbeck to Leidy project, the storage expansion project, the Appalachian Lateral 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. The Company had $458.8 million in Cash and Temporary Cash Investments at June 30, 2010, as shown on the Company s Consolidated Balance Sheet. The Company expects to use cash from operations as the first means of financing these projects, with short-term and long-term debt being used at a later time. Short-term debt may be used during 2010, but the Company does not expect to issue any long-term debt in conjunction with these projects until 2011.

For fiscal 2011, the Company expects to spend $128 million on Pipeline and Storage segment capital expenditures. Previously reported fiscal 2011 estimated capital expenditures for the Pipeline and Storage segment were $227 million. The decrease is attributable to the delay in the in-service date for the W2E pipeline project. The in-service date for the first facilities was moved from late 2012 to late 2013.

Exploration and Production

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2010 were primarily well drilling and completion expenditures and included approximately $12.0 million for the Gulf Coast region, the majority of which was for the off-shore program in the shallow waters of the Gulf of Mexico, $21.2 million for the West Coast region and $240.6 million for the Appalachian region (including $217.6 million in the Marcellus Shale area). These amounts included approximately $23.4 million spent to develop proved undeveloped reserves. The capital expenditures in the Appalachian region include the Company s acquisition of two tracts of leasehold acreage for approximately $71.8 million. The Company acquired these tracts in order to expand its Marcellus Shale acreage holdings. These tracts, consisting of approximately 18,000 net acres in Tioga and Potter Counties in Pennsylvania, are geographically similar to the Company s existing Marcellus Shale acreage in the area, and will help the Company continue its developmental drilling program. The transaction closed on March 12, 2010. The Company funded this transaction with cash from operations. It is anticipated that future capital expenditures during 2010 will be funded with cash from operations or short-term debt. Natural gas and crude oil prices combined with production from existing wells will be a significant factor in determining how much of the capital expenditures are funded from cash from operations.

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2009 were primarily well drilling and completion expenditures and included approximately $16.9 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, $28.8 million for the West Coast region and $106.0 million for the Appalachian region. These amounts included approximately $22.0 million spent to develop proved undeveloped reserves.

For fiscal 2011, the Company expects to spend $460 million on Exploration and Production segment capital expenditures. Previously reported fiscal 2011 estimated capital expenditures for the Exploration and Production segment were $488 million. Estimated capital expenditures in the West Coast region have increased from $28.0 million to $40.0 million. In the Appalachian region, estimated capital expenditures

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have decreased from $450.0 million to $410.0 million. Estimated capital expenditures in the Gulf Coast region have remained at the previously reported $10.0 million. The increase in the West Coast estimated capital expenditures is due to increased opportunities on California oil properties. The decrease in the Appalachian region estimated capital expenditures is due to a reduction in drilling plans for the Exploration and Production segment s shallow Upper Devonian program related to a decrease in natural gas prices.

All Other

The majority of the All Other category s capital expenditures for the nine months ended June 30, 2010 and June 30, 2009 were for the construction of Midstream Corporation s Covington Gathering System, as discussed below.

NFG Midstream Covington, LLC, a wholly owned subsidiary of Midstream Corporation, constructed a gathering system in Tioga County, Pennsylvania. The project, called the Covington Gathering System, was constructed in two phases. The first phase was completed and placed in service in November 2009. The second phase was placed in service in May 2010. The system consists of approximately 10 miles of gathering system at a cost of $13.7 million. During the nine months ended June 30, 2010 and June 30, 2009, Midstream Corporation spent $5.6 million and $2.8 million, respectively, related to this project.

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, 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 June 30, 2010. 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, which commitment extends through September 30, 2010. The Company has received commitments for a new three-year, syndicated committed credit facility totaling $300.0 million. The Company is negotiating the terms of the facility and expects to enter into the facility during the quarter ending September 30, 2010.

Under the Company s current 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 June 30, 2010, the Company s debt to capitalization ratio (as calculated under the facility) was .42. The constraints specified in the committed credit facility would permit an additional $1.98 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 June 30, 2010, the Company s

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long-term debt ratings were: BBB (S&P), Baa1 (Moody s Investor Service), and BBB+ (Fitch Ratings Service). In March 2010, Fitch Ratings Service decreased the Company s long-term debt rating from A- to BBB+. The Company does not believe that this ratings action will impact its access to the commercial paper markets. At June 30, 2010, 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 June 30, 2010, the Company would have been permitted to issue up to a maximum of $1.3 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.

The Company s 1974 indenture pursuant to which $99.0 million (or 7.9%) of the Company s long-term debt (as of June 30, 2010) 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 June 30, 2010, the Company had no debt outstanding under the committed credit facility.

The Company s embedded cost of long-term debt was 6.95% at June 30, 2010 and June 30, 2009. 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.

Current Portion of Long-Term Debt at June 30, 2010 consists of $200 million of 7.50% medium-term notes that mature in November 2010. Currently, the Company expects to refund these medium-term notes in November 2010 with cash on hand and/or short-term borrowings.

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 $22.9 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.

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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 nine months ended June 30, 2010, the Company contributed $20.2 million to its Retirement Plan and $21.4 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 $4.1 million to its VEBA trusts and 401(h) accounts.

Market Risk Sensitive Instruments

On July 21, 2010, the Wall Street Reform and Consumer Protection Act (H.R. 4173) was signed into law. The law includes provisions related to the swaps and over-the-counter derivatives markets. Under the law, the Company expects to be exempt from mandatory clearing and exchange trading requirements for most or all of its commodity hedges. Capital and margin requirements for these hedges are expected to be determined over the next year as regulators write more detailed rules and requirements. While the Company is currently reviewing the provisions of H.R. 4173, it will not be able to determine the impact to its financial condition until the final regulations are issued.

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 and liabilities 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 Net Derivative Liabilities (including any reduction for credit risk) are deferred until the hedged commodity transaction occurs in accordance with the provisions of the existing guidance for derivative instruments and hedging activities. The Level 3 Net Liabilities amount to $0.1 million at June 30, 2010 or less than 0.1% of the Total Net Assets shown in Part I, Item 1 at Note 2 Fair Value Measurements at June 30, 2010.

The decrease in the net fair value of the Level 3 positions from September 30, 2009 to June 30, 2010, as shown in Part I, Item 1 at Note 2, was attributable to an increase in the commodity price of crude oil relative to the swap price during that period. The Company believes that these fair values reasonably represent the amounts that the Company would realize upon settlement based on commodity prices that were present at June 30, 2010.

The fair value of all the Company s Net Derivative Assets was reduced by $0.7 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.

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

Rate and Regulatory Matters

Utility Operation

Base rate adjustments in both the New York and Pennsylvania rate 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 to 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 approved a 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 31st, and is applied to customer bills annually, beginning March 1st.

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 was 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. On February 1, 2010, the NYPSC filed a motion with the Court of Appeals, New York State s highest court, seeking permission to appeal the Appellate Division s annulment of that part of the rate order relating to disallowance of environmental clean up costs. On May 4, 2010, the NYPSC s motion was granted, and the matter will be heard by the Court of Appeals. The Briefing schedule began on July 28, 2010 and is followed by oral argument. The Company cannot predict 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 following three years of actual operation, in conjunction with which Empire will either justify Empire s existing recourse rates or propose alternative rates.

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

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 $14.8 million.

At June 30, 2010, 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 $17.5 million to $21.7 million. The minimum estimated liability of $17.5 million, which includes the $14.8 million discussed above, has been recorded on the Consolidated Balance Sheet at June 30, 2010. The Company expects to recover these environmental clean-up costs through rate recovery.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. The EPA has determined that stationary sources of significant greenhouse gas emissions will be required under the federal Clean Air Act to obtain permits covering such emissions beginning in January 2011. In addition, the U.S. Congress has been considering bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. Legislation or regulation that restricts carbon emissions could increase the Company s cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. Climate change and greenhouse gas measures could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. But legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

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

New Authoritative Accounting and Financial Reporting Guidance

In 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 nine months ended June 30, 2010. 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

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

immaterial. Additionally, in February 2010, the FASB issued updated guidance that includes additional requirements and disclosures regarding fair value measurements. The guidance now requires the gross presentation of activity within the Level 3 roll forward and requires disclosure of details on transfers in and out of Level 1 and 2 fair value measurements. It also provides further clarification on the level of disaggregation of fair value measurements and disclosures on inputs and valuation techniques. The Company has updated its disclosures to reflect the new requirements in Part I, Item 1 at Note 2 Fair Value Measurements, except for the Level 3 roll forward gross presentation, which will be effective as of the Company s first quarter of fiscal 2012.

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 used to value oil and gas reserves with 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 will be 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 will be effective as of the Company s first quarter of fiscal 2011. Given the current organizational structure of the Company, the Company does not believe this authoritative guidance will have any impact 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

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

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 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 derivatives, taxes, safety, employment, climate change, other environmental matters, and exploration and production activities such as hydraulic fracturing;

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

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;

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 derivatives, 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.

Industry and Market Information

The industry and market data used or referenced in this report are based on independent industry publications, government publications, reports by market research firms or other published independent sources. Some industry and market data may also be based on good faith estimates, which are derived from the Company s review of internal information, as well as the independent sources listed above. Independent industry publications and surveys generally state that they have obtained information from sources believed to be reliable, but do not guarantee the accuracy and completeness of such information. While the Company believes that each of these studies and publications is reliable, the Company has not independently verified such data and makes no representation as to the accuracy of such information. Forecasts in particular may prove to be inaccurate, especially over long periods of time. Similarly, while the Company believes its internal information is reliable, such information has not been verified by any independent sources, and the Company makes no assurances that any predictions contained herein will prove to be accurate.

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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 June 30, 2010.

Changes in Internal Controls Over Financial Reporting

There were no changes in the Company s internal control over financial reporting that occurred during the quarter ended June 30, 2010 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, as amended by Item 1A of the Company s Forms 10-Q for the quarters ended December 31, 2009 and March 31, 2010, have not materially changed.

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

On April 1, 2010, the Company issued a total of 3,600 unregistered shares of Company common stock to the nine non-employee directors of the Company then serving on the Board of Directors of the Company, 400 shares to each such director. All of these unregistered shares were issued under the Company s Retainer Policy for Non-Employee Directors as partial consideration for such directors services during the quarter ended June 30, 2010. These transactions were exempt from registration under Section 4(2) of the Securities Act of 1933, as transactions not involving a public offering.

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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]
Apr. 1 - 30, 2010	7,747	$ 52.37		6,971,019
May 1 - 31, 2010	8,298	$ 49.81		6,971,019
June 1 - 30, 2010	11,261	$ 48.66		6,971,019
Total	27,306	$ 50.06		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 June 30, 2010, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 27,306 shares purchased other than through a publicly announced share repurchase program, 24,154 were purchased for the Company s 401(k) plans and 3,152 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	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated June 1, 2010
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Twelve Months Ended June 30, 2010 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.
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 Statements of Income for the Twelve Months Ended June 30, 2010 and 2009.

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Item 6. Exhibits (Concl.)

101 Interactive data files pursuant to Regulation S-T: (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the three and nine months ended June 30, 2010 and 2009, (ii) the Consolidated Balance Sheets at June 30, 2010 and September 30, 2009, (iii) the Consolidated Statement of Cash Flows for the nine months ended June 30, 2010 and 2009, (iv) the Consolidated Statements of Comprehensive Income for the three and nine months ended June 30, 2010 and 2009 and (v) the Notes to Condensed Consolidated Financial Statements.

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SIGNATURES

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

NATIONAL FUEL GAS COMPANY
(Registrant)

/s/ D. P. Bauer
D. P. Bauer
Treasurer and Principal Financial Officer

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

Date: August 6, 2010